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ELECTRIC AND GAS UTILITY

PERFORMANCE BASED RATEMAKING MECHANISMS

(SEPTEMBER 2000 UPDATE)

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I.

Introduction and Background

Comments on the Update Report

This update report summarizes the operating components, results, and chronology of events pertaining to electric and gas utility performance-based ratemaking mechanisms (PBRs) adopted by the California Public Utilities Commission (CPUC). The update was prepared in September 2000 to include changes that occurred since the original report was issued in December 1997, and to clarify some points made in the original report. The main PBR-related events that have occurred since the first report was prepared are:

· conclusion of the original base rate PBR for San Diego Gas and Electric Company (SDG&E) and the adoption of new base rate PBR for that utility,

· the change of the Southern California Edison (SCE) PBR from a nongeneration PBR to a distribution PBR,

· the SCE PBR midterm review,

· termination of the SDG&E generation and dispatch PBR,

· the pending sale of Pacificorp to NorCal Electric,

· adoption of a modified SDG&E gas procurement PBR,

· adoption of an incentive mechanism for Other Operating Revenues for SCE and Pacific Gas and Electric Company (PG&E), and

· postponement of a base rate PBR for PG&E.

PG&E filed application A.98-11-023 for a base rate PBR in November 1998. In its decision on the 1999 General Rate Case for PG&E, D.00-02-046, the Commission decided to delay action on some components of the PG&E PBR proposal. PG&E subsequently petitioned to withdraw its application. Sierra Pacific filed an application for a base rate PBR in June 2000, and that application may be addressed by the Commission in 2000.

Introduction

Starting in 1989, a series of CPUC decisions involving the telecommunications industry provided a template with which the Commission could further explore incentive-based ratemaking mechanisms useful to the electric and gas industries. Specifically, in Decision (D.) 89-10-031, the Commission adopted a "new regulatory framework" centered around a price cap indexing mechanism with a sharing of excess earnings above a benchmark rate of return. The basic price indexing formula adjusts telecommunications rates for changes in inflation to allow for rising costs, reduced by a productivity adjustment to encourage greater efficiency. In D. 91-07-056 the CPUC expanded upon this theme by adopting a comprehensive monitoring program, in conjunction with "Z" factor provisions addressing exogenous influences on price caps, to compliment the nascent incentive based mechanisms.

In 1990, the Commission began an investigation into incentive-based ratemaking for gas utilities. (See R.90-02-008 and I.90-08-006) In 1991, the Commission found that an "indexing approach to nongas cost regulation could provide substantial benefits in increased efficiency, innovation, ratepayer protection, risk allocation, and regulatory simplicity." (D.91-03-032) Although the Commission deferred the implementation of an "indexing approach" for gas costs at that time, the Commission later adopted gas procurement mechanisms for San Diego Gas and Electric Company (SDG&E) in 1993, Southern California Gas Company (SoCalGas) in 1994, and Pacific Gas and Electric Company (PG&E) in 1997. In addressing SDG&E's proposal for a gas procurement PBR, the Commission stated in D.93-06-092:

> "For this or any other new regulatory approach to be effective, we must articulate clear standards of performance for the utility. Those standards should broadly cover gas purchasing activities to give the utility the flexibility to (1) make sound business decisions, without micromanagement by regulators, (2) develop innovative methods for improving performance and (3) adjust to changing circumstances.
>
> "SDG&E has proposed to replace after-the-fact reviews of its gas procurement operations with a market-based gas price benchmark. We see the proposal as an attempt to align ratepayer and shareholder interests through sharing of gains and losses. This proposal promises an

improvement over the current regulatory approach by providing lower gas costs to ratepayers than would be achieved under the status quo, and by reducing the regulatory burden and complexity for all parties." (D.93-06-092, slip op, pgs. 22-23)

The Commission adopted an Annual Energy Rate (AER) in the 1980's as an incentive for electric utilities to lower their fuel and power purchases, but as the Commission began investigating electric restructuring it expressed a policy preference for more comprehensive PBRs. The Commission's Division of Strategic Planning (DSP) issued a report in 1993 "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future", in which the DSP asserted the need for regulatory reform of the electric utility industry, and offered various recommendations, including the use of PBRs to replace general rate cases and reasonableness reviews. In Rulemaking (R.) 94-04-031/Investigation (I.) 94-04-032 the Commission initiated its investigation and rulemaking to consider a restructuring of the state's electric utility industry, and specifically proposed that performance-based regulation replace cost-of-service regulation for those electric utility services not fully subject to competition. The Commission found that contemporary cost-of-service regulation is ill suited to govern today's electric utilities, and that it is less well suited to govern the utility industries that are likely to emerge in the coming years. In its Preferred Policy Decision issued as a result of the investigation, D.95-12-063, the Commission continued to propose incentive regulation as a replacement for cost-of-service regulation. The Commission adopted a generation and dispatch PBR for SDG&E in 1993 and for Sierra Pacific in 1994, and adopted base rate PBRs for Pacificorp in 1993, for the SDG&E electric and gas departments in 1994, for Southern California Edison's (SCE) transmission and distribution system in 1996, and for SoCalGas in 1997. The Commission adopted a new SDG&E base rate PBR in May 1999, applicable to that company's electric distribution and gas departments. (PG&E filed an application for a base rate PBR in November 1998, but that application was withdrawn pursuant to the Commission's decision on the 1999 PG&E General Rate Case. Sierra Pacific filed an application for a PBR proposal in June 2000.)

By the late 1990's, the Commission had firmly established performance-based regulation as its preference over cost-of-service regulation for those regulated utility services where competition has not yet been established or fully matured. The Commission has set forth the following objectives for PBRs:[1]

a. To provide greater incentive than exists under current regulation for the utility to reduce rates.

b. To provide a more rational system of incentives for management to take reasonable risks and control costs in both the long and short run. This includes extending the relatively short-term planning horizon associated with the three-year GRC cycle, and reducing the company's incentive to add to rate base to increase earnings.

c. To prepare the company to operate effectively in the increasingly competitive energy utility industry. This entails providing greater flexibility for management to take risks combined with a greater assignment of the consequences of those risks to the company.

d. To reduce the administrative cost of regulation.

The Commission adopted five basic types of PBRs and incentive mechanisms for energy utilities: 1) base rate PBRs to replace general rate cases, cost of capital proceedings, and attrition adjustments; 2) gas procurement PBRs to replace reasonableness reviews of gas utility procurement practices; 3) electric utility generation and dispatch incentive mechanisms to replace the reasonableness reviews of electric utility operation; 4) nuclear unit incentive mechanisms, and; 5) incentive mechanisms for Other Operating Revenues. Nuclear unit incentive mechanisms are not discussed in this report. With electric restructuring in California, the electric base rate PBRs have been applicable only to electric utility distribution systems, and generation and dispatch PBRs have been terminated. However, PBRs have been proposed for aspects of electric generation and pricing since electric restructuring began. For example, SCE has proposed a hydroelectric generation PBR, and SDG&E and PG&E proposed a PBR to govern its electric commodity costs. The Commission has not yet reached a decision regarding the SCE proposal, but rejected the SDG&E and PG&E electric PBR proposals in D.00-06-034.

The PBR descriptions in this report are not intended to be fully detailed and comprehensive, but are intended to give an overview of the different PBR structures and components. PBR structures, components, and details change over time due to various modifications, restructuring, or termination. In order to review the most current details of the various PBR mechanisms, the reader is advised to refer to the decisions adopting the PBRs and the Preliminary Statement of the tariffs of the various utilities.

II.

COMPONENTS

AND

RESULTS OF BASE RATE PBR MECHANISMS

The base rate[2] PBRs which have been adopted by the Commission to date generally have seven main components: 1) a starting point revenue requirement or rates, typically established in a general rate case or cost-of-service review; 2) a PBR formula to establish revenue requirements, revenue per customer, or rates in subsequent years which are indexed to some measure of inflation and productivity; 3) a mechanism by which rates or revenue requirements are adjusted to account for changes in the cost of capital, usually called a "cost of capital trigger" mechanism; 4) some type of revenue or earnings sharing component, whereby ratepayers and shareholders share actual revenues compared

to authorized; 5) a reward or penalty system used as an incentive to maintain or improve utility service, safety, and customer satisfaction performance compared to established benchmarks; 6) "Z-factors" and exclusions to account for highly unusual events and costs which aren't appropriate for a PBR; and 7) a monitoring and evaluation program.

II.A. SDG&E Base Rate PBR Mechanism

In D.99-05-030, the Commission adopted a new base rate PBR for SDG&E, effective January 1, 1999. (SDG&E's original PBR had been in effect from 1994 through 1998, and is described in Appendix 2.) SDG&E's new PBR will be in effect through 2002. SDG&E is required to file a cost-of-service study for the year 2003 no later than December 21, 2001. The SDG&E PBR includes a "rate indexing" formula (as opposed to a "revenue indexing" formula); a revenue sharing mechanism; service quality performance incentives and service guarantees; a "Z" Factor allowance for exogenous influences; and a monitoring and evaluation program. A cost of capital adjustment mechanism was adopted in a separate proceeding.

II.A.1 SDG&E Base Rate PBR Starting Point Revenue Requirements and Rates

The 1999 starting point revenue requirement for the new PBR was adopted by the Commission in D.98-12-038. Along with its PBR proposal in A.98-01-014, SDG&E presented a cost-of-service study to develop its 1999 revenue requirement for electric distribution and the gas department. A settlement was reached among the active parties in that proceeding on the 1999 revenue requirement, and the settled amounts were adopted in D.98-12-038. Starting point rates were developed using forecasted electric and gas sales for 1999, also settled by parties and adopted by the Commission in D.98-12-038.

II.A.2 SDG&E Base Rate PBR Rate Indexing Formula

The two main types of indexing formulas debated in A.98-01-014 were the "rate index" and the "revenue per customer" index. In D.99-05-030, the Commission adopted a rate index for the new SDG&E PBR. Starting point electric distribution and gas rates are to be multiplied annually by an inflation factor less a productivity factor to establish rates in future calendar years. The adopted inflation factors are based on inflation factor forecasts developed by DRI for gas and electric utility labor, non-labor, and capital-related costs. These factors are weighted using California utility weighting percentages to develop gas and electric distribution inflation factors. DRI's forecasts for inflation factors are trued up for historical inflation in subsequent years, using DRI's estimates of historical inflation. The adopted electric distribution productivity factor is 1.32% for 2000, 1.47% for 2001, and 1.62% for 2002. The adopted gas productivity factor is 1.08% for 2000, 1.23% for 2001, and 1.38% for 2002.

II.A.3 SDG&E Base Rate PBR Cost of Capital Trigger Mechanism

In D.96-06-055, a Market Indexed Capital Adjustment Mechanism (MICAM) was adopted for SDG&E, whereby SDG&E's authorized cost of capital would change with significant changes in single-A rated utility bond rates. D.99-05-030 did not revise the basic MICAM formula. A new cost of capital was adopted for SDG&E in D.99-06-057 for 1999, but the MICAM will remain in place as the mechanism for future adjustments in SDG&E's cost of capital. SDG&E filed A.00-03-062 to retain the MICAM at least through the end of 2002.

II.A.4 SDG&E Base Rate PBR Revenue Sharing Component

SDG&E's PBR contains an incentive-based "sharing" mechanism wherein the utility strives to reduce its operating costs, by competing against an established benchmark for its ROR. The SDG&E revenue sharing component is very similar to that of SoCalGas. The mechanism is calibrated by setting the ROR benchmark at the currently authorized ROR. A 25 basis point "deadband" above the benchmark is established to account for minor fluctuations in operations.

Between 25 basis points and 300 basis points above the benchmark there are eight bands of sharing tiers. In the first band, from 25 to 75 basis points, shareholders to receive 25% of the marginal revenues and ratepayers 75%. Each successive band allows an increase of 10% to shareholders and a decrease of 10% to ratepayers. The sixth band, between 175 and 200 basis points, shows shareholders receiving 75% and ratepayers 25%. In the seventh band, between 200 and 250 basis points, shareholders receive 85% and ratepayers 15%. In the eighth band, between 250 and 300 basis points, shareholders retain 95% of the profits and ratepayers 5%.[3] Above 300 basis points over the authorized ROR, SDG&E shareholders receive 100% of incremental revenues.

II.A.5 SDG&E Base Rate PBR Quality of Service Incentives

SDG&E's new base rate PBR mechanism includes several performance indicators which reward or penalize the utility's performance measured against an established benchmark in employee safety, customer satisfaction, telephone response time, and electric system reliability. The maximum yearly reward or penalty for the performance indicators is $14.5 million.

Employee Safety

For employee safety, the maximum reward or penalty is $3 million. The standard compares SDG&E's regulated Occupational Safety Health Administration (OSHA)-reportable lost time and non-lost time injuries and illnesses, as adjusted for personnel changes due to the approved merger between Enova and Pacific Enterprises to an adopted benchmark frequency for those injuries and illnesses. The benchmark is 8.80 units, and there is a deadband of 0.2 above and below the benchmark. The $3 million reward is reached if actual performance met or was less than an OSHA loss time frequency of 7.4. The $3 million penalty is reached if actual performance met or exceeded an OSHA loss time frequency of 10.2. The incentive penalty or reward changes by $25,000 for every 0.01 units outside the deadband, up to the maximum amount.

Customer Satisfaction

The customer satisfaction indicator utilizes SDG&E's Customer Service Monitoring System (CSMS) results from the prior year, and has a benchmark of 92.5% "very satisfied" responses from customers surveyed. A deadband ranges from 92.0% to 93.0%. Rewards and penalties increase symmetrically in increments of $75,000 for each 0.1% above or below the deadband. The maximum reward or penalty is $1.5 million for 95% or 90% "very satisfied" responses, respectively. SDG&E's CSMS has been in place since the 1970's and customer responses number over 10,000 per year. The survey is structured to measure customer satisfaction tied to specific service quality issues rather than general opinions about rates or public image. To ensure validity, the annual CSMS data is audited by an unbiased third party.

System Reliability

Electric system reliability is measured using three standards, one for system average interruption duration, one for system average interruption frequency, and one for momentary interruption frequency. The system average interruption duration reliability indicator benchmark utilizes SDG&E's System Average Interruption Duration Index ("SAIDI"). The index measures the average annual duration of certain service interruptions per customer, excluding planned outages and major events such as earthquakes and severe storms. The maximum annual reward or penalty is $3.75 million. The benchmark will be 52 minutes in 1999, 2000, and 2001, excluding underground

cable failures. In 2002, the benchmark will be 73 minutes, including underground cable failures. Each intermediate minute was worth $250,000 in rewards or penalties.
The system average interruption frequency reliability indicator benchmark utilizes SDG&E's System Average Interruption Frequency Index ("SAIFI"). The index measures the average annual frequency of electric distribution system forced outages of five minutes or more for each customer, excluding major events. The maximum annual reward or penalty is $3.75 million. The benchmark will be 0.90 outages per year. Each intermediate 0.01 unit is worth $250,000 in rewards or penalties.
The momentary interruption frequency reliability indicator benchmark utilizes SDG&E's Momentary Average Interruption Frequency Index ("MAIFI"). The index measures the average annual frequency of electric distribution system forced outages of less than five for each customer, excluding major events. The maximum annual reward or penalty is $1 million. The benchmark will be 1.28 outages per year. Each intermediate 0.015 unit is worth $50,000 in rewards or penalties.
There are no deadbands for any of the system reliability performance indicators.

CALL CENTER TELEPHONE RESPONSE TIME

This performance indicator measures SDG&E's responsiveness to customer telephone inquiries. The benchmark is 80% of calls answered in 60 seconds, as measured on an annual basis. There is no deadband. For each 0.1% change in performance results, the incentive increases by $10,000 up to a maximum reward or penalty of $1.5 million.

SERVICE GUARANTEES

This component provides a credit to customers if SDG&E does not meet its scheduled appointment time for service visits at the customer's premises. Basically, the customer may receive a credit for between $15 and $50 if SDG&E does not arrive within its scheduled time frame and does not notify the customer in advance. The amount of the credit depends on the type of service visit.

II.A.6 SDG&E Base Rate PBR Z-Factors and Exclusions

SDG&E is afforded "Z-factor" treatment for certain significant costs associated with highly unusual events. Z-factor treatment is allowed for costs which meet nine criteria, previously adopted for Edison and SoCalGas. These criteria are:
· The event causing the cost must be exogenous to the utility.
· The event must occur after implementation of the PBR.
· The utility cannot control the costs.
· The costs are not a normal cost of doing business.
· An event affects the utility disproportionately.
· The PBR update rule must not implicitly include the cost.
· The cost must have a major impact on the utility.
· The cost impact must be measurable.
· The utility must incur the cost reasonably.
When a potential Z-factor event occurs, SDG&E must file an advice letter and establish a memorandum account for the event. SDG&E's shareholders absorb the first $5 million per Z-factor event. PBR rates will be adjusted for Z-factor costs if approved by the Commission.

Aside from electric generation and transmission costs and expenses, various other costs and expenses are also excluded from the PBR mechanism. Some costs are excluded from the update rule. These costs include tree trimming expenses, NGV program costs, gas RD&D costs, fixed A&G costs which the utility may be able to recover through O&M service contracts for its divested power plants, year 2000 computer expenses, DSM program rewards. Some items are excluded from recorded revenues and/or expenses in the calculation of the ROR for revenue sharing purposes. These items are tree trimming revenues and expenses, senior executive retirement plans and executive bonuses, NGV program costs in 1999 and 2000, gas RD&D costs, any under run of the fixed A&G costs associated with maintenance contracts for divested power plants, hazardous waste costs, CEMA costs, and rewards associated with DSM, PBR performance indicators, and nuclear unit incentives.

II.A.7 SDG&E Base Rate PBR Monitoring and Evaluation Program

On February 15th of each year, starting in 2000, SDG&E must file an annual PBR performance report that addresses the performance indicators and earnings sharing results for the previous calendar year. This report will be filed by advice letter. SDG&E must also submit quarterly reports to the Energy Division and interested parties that address the 12-months-to-date sharing and year-to-date performance indicator results. The CPUC's Energy Division expects to conduct thorough reviews of the annual PBR report.

SDG&E files an annual advice letter on October 1st to update its rates for the following calendar year using the PBR update formula.

By June 30, 2000 SDG&E must file an application to develop evaluative criteria for a comprehensive review of its PBR. This application was filed by SDG&E on June 30, 2000. The Energy Division will conduct a review of the PBR mechanism by the end of 2000, or it may hire a consultant to undertake such a review.

II.A.8 SDG&E Base Rate PBR Results

The 1999 electric distribution and gas rates have been updated for the year 2000 using the PBR escalation formula adopted in D.99-05-030.

SDG&E filed its reported 1999 PBR performance results on March 15, 2000, but these results have not yet been adopted by the Commission at the time of this report. For information, these SDG&E-reported results are summarized here:

1999 Actual ROR: 9.28%
1999 Authorized ROR: 9.05%
No ratepayer sharing of earnings
Performance Rewards/(Penalties)
Employee Safety $1,550,000
Customer Satisfaction $ (300,000)

CALL CENTER $ 670,000

<u>System Reliability</u>
System Average Interruption Index (SAIDI) $3,025,000
System Average Interruption Frequency Index (SAIFI) $3,750,000
Momentary Average Interruption Frequency Index (MAIFI) <u>$1,000,000</u>
Net Reward $9,695,000

II.B. Southern California Edison (SCE) Transmission and Distribution (T&D) PBR

The Commission adopted an SCE Transmission and Distribution (T&D) PBR in D.96-09-092 (A.93-12-029). The SCE T&D PBR was implemented on January 1, 1997 and the basic form of the PBR is scheduled to operate through December 31, 2001. (SCE is expected to file a 2002 GRC in late 2000.) Beginning in 1998, with the implementation of electric restructuring, the SCE PBR became applicable only to the distribution component of SCE's rates. The SCE PBR mechanism includes a "rate indexing" formula (as opposed to a "revenue indexing" formula); a revenue sharing mechanism; a cost of capital trigger mechanism; service quality performance incentives; a "Z" Factor allowance for exogenous influences; and a monitoring and evaluation program.

II.B.1. SCE Base Rate PBR Rate Indexing Formula

The starting point for the T&D PBR was initially derived from the separation of generation and nongeneration Authorized Level of Base Rate Revenues (ALBRR's). Nongeneration accounts include: transmission, distribution, customer accounts, customer service and information, and administrative and general. In 1998, the SCE PBR became a distribution PBR, and no longer includes transmission-related expenses, costs, and revenues. The rate indexing mechanism takes distribution rates adopted for an initial year (in this case, the unbundled distribution rates developed from SCE's 1996 Test Year GRC, D.96-01-011) and, in subsequent years of the PBR, changes these initial rates by applying an inflation factor minus a productivity factor (also known as the "update rule," or CPI - X).4

The Consumer Price Index (CPI) represents the inflation measure for the SCE Rate Indexing Mechanism. The productivity measure ("X") began with a value of 1.2 in 1997, increased to 1.4 in 1998, and to 1.6 in 1999 to 2001.

II.B.2. SCE Base Rate PBR Revenue Sharing Mechanism

The revenue sharing mechanism provides for sharing of net distribution revenues between customers and shareholders when the actual earned return on equity is above or below a benchmark rate. Here, the benchmark return on equity is initially established by the Commission in its most recent Cost of Capital proceeding, and then is governed by a Cost of Capital "trigger" mechanism (see following section).

The sharing mechanism is symmetric and has three bands:

· Inner Band
- 50 basis points around the benchmark
- Shareholders receive all net revenue gains or losses

· Middle Band
- 50 to 300 basis points around the benchmark
- shareholders' marginal share of gains or losses rises
from 25 to 100 percent

· Outer Band
- 300 to 600 basis points around the benchmark
Shareholders receive all marginal gains or losses

*At 600 basis points or more from the benchmark, the PBR mechanism is reevaluated.

II.B.3. SCE Base Rate PBR Cost of Capital Trigger Mechanism

The distribution PBR generally replaces SCE's annual Cost of Capital proceeding with an automatic Cost of Capital "Trigger Mechanism." This mechanism tracks changes in the AA utility bond rates, and resets the authorized return on the equity share of the distribution rate base in order to adjust the authorized return on equity and the benchmark of the Net Revenue Sharing Mechanism. With the Trigger Mechanism, the utility's authorized return on equity changes by half the change in a AA bond index value but only when the last 12 months of this index, averaged from October through September, show a cumulative change of 100 basis points from its base value. When this change occurs, it triggers Edison's authorization to file for an automatic increase in its equity return. This change also resets the base value of the index to the most recent 12-month average for the bond index.

Edison selected a specific AA bond index5 for its Trigger Mechanism and will track the monthly composition of its index in its annual PBR report.

II.B.4. SCE Base Rate PBR Z-Factors and Exclusions

a) Z-Factors

To account for major events beyond the utility's control, such as changes in tax laws or natural disasters, the Commission includes a Z-Factor provision in the SCE PBR. To be eligible for Z-Factor treatment, the event must be analogous to those outlined in the telecommunication's New Regulatory Framework (NRF) as summarized below:

· The event causing the cost must be exogenous to the utility.
· The event must occur after implementation of the PBR.
· The utility cannot control the costs.
· The costs are not a normal part of doing business.
· An event affects the utility disproportionately.
· The PBR update rule must not implicitly include the cost.
· The cost must have a major impact on the utility.
· The cost impact must be measurable.
· The utility must incur the cost reasonably.

After identifying potential Z-Factor costs, Edison is required to report them to the Commission and to apply for Z-Factor treatment in its annual filing for rate changes. The Z-factor procedural schedule is set on a case-by-case basis without predetermined deadlines. A $10 million deductible is applied on a one-time basis to each Z-factor authorized for recovery by the Commission.

b) Exclusions[6]

The following programs were originally excluded from the scope of the SCE PBR:

· Generation-related revenues and costs
· Transmission-related revenues and costs
· Amounts in special one-time amortization accounts
· RD&D
· DSM
· Hazardous Substance Clean-up Cost Recovery

In D.99-09-070, the Commission adopted an incentive mechanism for SCE's Other Operating Revenues (OOR). With the adoption of this mechanism, OOR revenues above a certain threshold and expenses are no longer included as PBR-related revenues and expenses. (See the OOR section later in this report.)

II.B.5. SCE Base Rate PBR Service, Safety, and Customer Satisfaction Measures

Service quality components are included in the SCE distribution PBR which Measure SCE's performance in the areas of service reliability, customer satisfaction, and employee health and safety. All three measures provide the utility with incentives to improve service quality.

a) Service Reliability

Outage Duration

To encourage continued improvements in service reliability, the PBR contains an initial benchmark standard for Average Customer Minutes of Interruption (ACMI) of 59 minutes in 1997. This benchmark declines by two minutes in each subsequent year. This benchmark has a deadband of six minutes on each side of the benchmark. However, in recognition of the conflict between requiring the utility to improve performance and year-to-year variability of performance, the Commission will not impose any penalty on Edison if it achieves an average no higher than 55 minutes for the period 1997 through 2001. Performance is measured by a rolling two-year average. Rewards and penalties occur at a rate of $1 million per minute over and above the deadband, with a maximum of $18 million for both duration and frequency.

Outage Frequency

The PBR contains a standard of 10,900 annual interruptions, with a deadband of 1,100 on each side of the benchmark. Again, to tie the incentive to longer term trends-- thus reducing the impact of random variation-- performance is measured by a rolling two-year average. Symmetrical rewards and penalties occur at a rate of $1 million per 183 interruptions, with a maximum of $18 million for both duration and frequency.

b) Customer Satisfaction

Each year, Edison, in conjunction with an outside consulting firm, conducts a survey to measure customer satisfaction in four service areas: field services and meter reading;

local offices; telephone centers; and service planning. In each of the areas surveyed, the utility asks a variety of questions, including a question as to the respondent's overall satisfaction with the specific service provided. Customers choose among six satisfaction categories with the top two being "completely satisfied" and "delighted." The utility is rewarded or penalized $2 million for each percentage point above or below the historic performance standard 64%, with a deadband of three percent on each side of the benchmark.

The utility can be rewarded up to $10 million through this mechanism, but will not receive a reward if ten percent of customers fall in the bottom two of the six response categories surveyed.

In addition, Edison can be penalized up to $10 million if performance in any one of four survey areas falls below 56%.

c. Health and Safety

This component of the distribution PBR rewards or penalizes Edison for its performance in employee health and safety. The standard consists of a ratio index of the total number of accidents and illnesses per 200,000 hours worked or per 100 employees. The specific benchmark is a value of 13.0 with a deadband of 0.3. An incentive of about $555,000 for each 0.1 increase/decrease in the index is assessed, with a maximum reward or penalty of $5 million.

II.B.6 SCE Base Rate PBR Monitoring and Evaluation

SCE files an annual advice letter on November 1st to adjust its rates according to the rate indexing mechanism, for the following calendar year. It also reports any cost of capital changes necessary, as a result of the cost of capital trigger mechanism. On March 31st, SCE files its annual performance report reviewing the revenue sharing results of the previous calendar year, and its performance compared to the performance indicator benchmarks.

As discussed below, SCE filed a midterm review report on March 1, 1999 (A.99-03-020), including several reports specified by the Commission in D.96-09-092, and SCE's PBR underwent a midterm review from March to December 1999.

Finally, in D.96-09-092, the Commission ordered that SCE convene a working group process in 1997 to assess the need for additional standards for evaluation. This working group, composed of large and small ratepayer representatives, other utilities, a utility employee representative, and SCE, met several times in the summer and fall of 1997.

II.B.7 SCE Base Rate PBR Results

SCE's 1997 electric distribution rates have been updated for the years 1998, 1999, and 2000 using the PBR escalation formula adopted in D.96-09-092.

The 1997 performance results for SCE under its PBR were reported in its advice letter (AL) 1302-E filed March 31, 1998. That advice letter was supplemented twice by AL 1302-E-A and 1302-E-B, filed on June 1, 1999 and July 16, 1999, respectively. In Resolution E-3656, the Commission adopted a Health and Safety reward for 1997, but ordered SCE to recalculate the revenue sharing amount to exclude certain expenses from PBR operating expenses. SCE submitted its recalculation on May 5, 2000.

SCE reported its results for 1998 in AL 1373-E and 1373-E-A, filed on March 31, 1999 and June 1, 1999, respectively. SCE reported its results for 1999 in AL 1449-E, filed on April 14, 2000. These results are still under review by the Commission. SCE's reported performance results are shown below:

SCE PBR Reported Performance Results

1997 1998 1999

Adopted Reported Reported

Actual ROE 13.50% 11.16% 11.31%

Authorized ROE 11.6% 11.6 % 11.6%

Ratepayer Sharing $40.56 0 0
($ millions)

Service Reliability

ACMI Actual (minutes) 56 65 50
ACMI Benchmark 58 56
Two-year ACMI Avg. (min.) N.A. 60 57
Reward/(Penalty) N.A. 0 0
Outage Frequency Actual 8987 9913 9107
Outage Benchmark 10900 10900
Two-year Actual Avg. N.A. 9450 9510
Reward/(Penalty) ($ millions) N.A. $2.0 $2.0

Customer Satisfaction

Survey % 66% 71% 72%
Benchmark 64% 64% 64%
Reward/(Penalty)($ millions) 0 $8.0 $10.0

Health & Safety

Actual Performance 10.1 7.9 6.4
Benchmark 13.0 13.0 13.0
Reward/(Penalty)($ millions) $5.0 $5.0 $5.0

II.B.8 SCE Base Rate PBR Midterm Review

For its mid-term review, SCE had been ordered by the Commission to make a number of filings and address certain issues, including:

1. a study that defines an industry-specific price index and proposes such an index,
2. a showing that the joint effect of the Trigger Mechanism and the CPI provides appropriate compensation for SCE's ROE,
3. a study showing the value of SCE's service to customers,
4. a summary description of a component database that provides detail to the distribution circuit level,
5. an examination of the interaction between the reliability incentives, particularly the duration mechanism, and the net revenue sharing mechanism,
6. a more objective measure of customer satisfaction than the customer survey,
7. a review of the health and safety mechanism with regard to the severity of accidents, and
8. a review of business office closure procedures.

SCE filed A.99-03-020 to address these issues, the Energy Division conducted a workshop in June 1999, and the Energy Division issued a workshop report in July 1999. In D.99-12-035, the Commission issued its opinion on the SCE midterm review. While the Commission did not order any specific changes to the PBR, it required SCE to prepare some studies and collect certain data.

II.B.9. Examination of the SCE Base Rate PBR Service Reliability Component

> In D.96-11-021, the Commission stated its intent to adopt PBR standards for maintenance, repair, and replacement (MR&R) of major electric distribution facilities, and ordered the major California electric utilities to file in a PBR proceeding proposed performance standards for these activities no later than July 1, 1998. On December 31, 1997, SCE filed A.97-12-047 in compliance with this order, and asserted that no changes to its existing PBR mechanism was necessary. Various parties filed comments on SCE's application, and a workshop was convened by the Commission's Energy Division to address various aspects of SCE's application and the requirements of D.96-11-021. The workshop was held in May 1998, and the Energy Division issued a report on the workshop in June 1998. In D.98-08-015 the Commission found that Edison's proposed MR&R PBR in A.97-12-047 complied with D.96-11-021 on an interim basis, and certain data collected by SCE on distribution failure rates might be used to develop a more specific PBR mechanism for MR&R at a later date.

II.C. SoCalGas Base Rate PBR

The SoCalGas Base Rate PBR was adopted by the Commission on July 16, 1997 in D.97-07-054. SoCalGas' Base Rate PBR includes: a "revenue per customer indexing" formula; revenue sharing; a cost of capital trigger mechanism; Z-Factors and exclusions; service quality, customer satisfaction, and safety incentives, and; a monitoring and evaluation program.

II.C.1. SoCalGas Base Rate PBR Revenue Requirement Per Customer Indexing Mechanism

The SoCalGas PBR indexing method uses three measures: inflation, productivity, and customer growth.

SoCalGas' specific indexing formula is:

PBR rev. req. per customer (year 2) = PBR rev. req. per customer (year 1) *x* [1+inflation - X]

The inflation index is a weighted average of forecasted inflation factors for gas utility labor O&M, non-labor O&M, and capital-related costs. The weighting percentages are the average percentages of the costs in each of these three categories for gas operations for SoCalGas, PG&E, and SDG&E. The forecasted inflation index is later trued-up for actual inflation.

The Productivity Factor ("X") has three parts. The first component is a historic measure of industry productivity, in this case 0.5%. The second component represents an additional ramped productivity target based upon "potential incremental productivity improvements that the utility can expect to achieve over and above the historical average." This "stretch factor" creates a consumer dividend by applying downward pressure on costs, and by extension, on rates.

The Commission also included a 1.0% increase to the ramped stretch productivity factor to account for potential rate base reductions under SoCalGas management's control. This additional increase results in a total X factor of 2.1% in Year 1; 2.2 percent in Year 2; 2.3 percent in Year 3; 2.4 percent in Year 4; and 2.5 percent in Year 5.

Once the revenue requirement per customer is calculated, that figure is then multiplied by a forecasted number of customers for the following year. After the year is over, the authorized revenue requirement is "trued-up" to account for the actual average number of customers during the year.

II.C.2. SoCalGas Base Rate PBR Revenue Sharing Mechanism

SoCalGas' PBR contains an incentive-based revenue sharing mechanism wherein the utility strives to reduce its operating costs, by competing against a established benchmark for the ROR. The mechanism is calibrated by setting the ROR benchmark at the currently authorized ROR. A 25 basis point "deadband" above the benchmark is established to account for minor fluctuations in operations.

Between 25 basis points and 300 basis points above the benchmark there are eight bands. In the first band, from 25 to 50 basis points, shareholders to receive 25% of the marginal revenues and ratepayers 75%. Each successive band allows an increase of 10% to shareholders and a decrease of 10% to ratepayers. The sixth band, between 150 and 200 basis points, shows shareholders receiving 75% and ratepayers 25%. In the seventh band, between 200 and 250 basis points, shareholders receive 85% and ratepayers 15%. In the eighth band, between 250 and 300 basis points, shareholders retain 95% of the profits and ratepayers 5%.[7]

SoCalGas' shareholders are a risk for all ROR *below* the benchmark**.**

Table 3
SoCalGas PBR Sharing Mechanism

Shareholders	**Ratepayers**		**Basis Points Over or Above Authorized ROR**	
100%	**0%**		**+300**	
95	**5**		**250**	
85	**15**		**200**	
75	**25**		**150**	
65	**35**		**125**	
55	**45**		**100**	
45	**55**		**75**	
35	**65**		**50**	
25	**75**		**25**	
100	**0**		**0**	
Benchmark Rate of Return				
100	**0**		**-175**	

II.C.3. SoCalGas Base Rate PBR Z-Factors and Exclusions

Z-factor provisions allow for unexpected events causing uncontrollable costs to be handled outside of the mechanism. When a potential Z-factor occurs, SoCalGas promptly notifies the Commission of its occurrence and establishes a detailed memorandum account for the event. The notification is followed by a supplement to annual rate adjustment procedures for Commission review.

The utility's shareholders will absorb the first $5 million per event of otherwise compensable Z-factor adjustments. This is the utility's "deductible." The deductible is cumulative for each Z-factor event from year to year, and is exhausted when the cumulative Z-factor costs exceed the deductible amount. The deductible is applicable to each separate Z-factor event.

Several cost categories, either beyond the control of SoCalGas' management or handled by existing regulatory mechanisms, will continue to be excluded from the PBR. These would be preserved, and would maintain their separate existence for adjudication by the Commission.

They are:

· Catastrophic Event Memorandum Account (CEMA)
· Hazardous Substance Cost Recovery Account (HSCRA)
· Low Emission Vehicle (LEV) Program
· Regulatory Transition Costs
· Wheeler Ridge Interconnection Costs and Revenues
· Mandated Social Programs
· Gas Costs and Pipeline Demand Charge
· Costs Imposed by the Commission

II.C.4. SoCalGas Base Rate PBR Cost of Capital Trigger Mechanism

In addition to offramps in the sharing mechanism, the SoCalGas PBR provides a "trigger" in the event of a dramatic change in cost of capital as reflected in the 12-month trailing average yield on long-term Treasury Bonds. Compared to the yield forecast for calendar year 1997 in SoCalGas' cost of capital application, if increases exceeding 150 basis points in the bond yield occurred and the then-current DRI forecast indicated continued increases of at least 150 basis points difference from the benchmark interest rate under PBR, rates would automatically be adjusted according to a pre-established formula similar to that adopted for the SDG&E MICAM. Changes are not retroactive but are effective from the date of the Commission's decision.

II.C.5. SoCalGas Base Rate PBR Performance Indicators

The SoCalGas PBR's Performance Indicators include: (1) customer satisfaction, (2) service quality, and (3) employee safety. Individual targets are established for the three key performance attributes, with each attribute carrying a potential penalty should the performance level fall below a benchmark standard.

Customer Satisfaction

Customer Satisfaction component benchmarks are comprised of four main target areas. The target areas and corresponding targets are:

(1) Customer satisfaction with the telephone customer service representative (CSR) with a target of 90.7% ;
(2) Customer satisfaction with the scheduling of an appointment for a field service call with a target of 79.1%;
(3) Satisfaction with the field Appliance Service Representative (ASR) with a target of 94.3%; and
(4) Percentage of on-time arrival for the service call with a target of 95.2%.

The benchmarks are based upon the average performance for 1994 through 1996 for each of the four target areas, measured as the percentage of customers "satisfied" with the service provided (i.e., responding with a 8, 9, or 10 on a 10 point scale) on the first three target areas, and the percentage "yes" responses on the on-time arrival attribute. Each service attribute carries a potential penalty and each carries a one-point deadband below the target. Should the utility's performance fall below the deadband, it will be penalized $10, 000 per 0.1 point decline for the first point below the deadband. SoCalGas will be penalized $20, 000 per 0.1 point decline thereafter. No reward is provided for the customer satisfaction component of the SoCalGas PBR.

A call center performance standard requires 80% of all telephone calls to be answered within 60 seconds for regular calls, and 90% of all leak and emergency telephone calls to be answered with 20 seconds. SoCalGas is penalized $20, 000 per 0.1 point decline below each standard (i.e., 80% and 90%), with no deadband. Again, no reward is provided for in this telephone response time component.

SoCalGas also assumes responsibility to provide reports to the Commission, on a quarterly basis, containing monthly data on several service quality indicators. These include: level of telephone busy signals, percentage of estimated meter readings, leak response time, percentage of missed appointments, and percentage of customer problems resolved on the first call. Aggregate penalties of more than $4 million will trigger an investigation by the Commission.

Employee Safety

An annual employee safety standard measures the number of incidents per 200, 000 hours worked. The annual measure for the benchmark is an OSHA Recordable Injury and Illness Rate, now set at 9.3 incidents, with a symmetrical deadband of 1.0. Rewards are distributed if SoCalGas' performance falls below 8.3. Conversely, penalties will be assessed if performance exceeds the 10.3. Both penalties and rewards are assessed at $20, 000 per 0.1 point outside the deadband.

II.C.6. SoCalGas Base Rate PBR Monitoring and Evaluation

SoCalGas is required to file an annual PBR performance report similar in scope to the one filed by SDG&E. This report should not only review the PBR's performance, including a report of any sharable earnings, but should also address issues of service quality, customer satisfaction, and safety incentives. The following schedule outlines SoCalGas' filing requirements:

April 1 - SoCalGas provides a draft sharable earnings advice letter to appropriate Commission staff, which includes workpapers detailing operating results for SoCalGas' base rates.

July 1 - Commission staff may submit a report on its audit or analysis of SoCalGas' draft sharable earnings results.

July 10 - SoCalGas files its final performance advice letter, with supporting workpapers.

July 31 - Protests in accordance with General Order 96-A can be filed.

SoCalGas also files on October 1st an advice letter which revises the utility's authorized revenue requirement for the following calendar year.

Finally, a mid-course review was ordered, to be undertaken during SoCalGas' 1998 Biennial Cost Allocation Proceeding (BCAP).

II.C.7. SoCalGas Base Rate PBR Results

The SoCalGas base rate PBR became effective January 1, 1998. SoCalGas reported the following PBR performance results for the year 1998:

SoCalGas' 1998 Approved and 1999 Reported

PBR Performance Results

	1998 Approved	1999 Reported
Actual ROR	9.02%	10.13%
Authorized ROR	**9.49%**	**9.49%**
Ratepayer Sharing ($ millions)	0	$8.3
Customer Rep. Performance		
Performance	91.9%	92.2%
Penalty	0	0
Appointment Scheduling		
Performance	81.7%	83.2%
Penalty	**0**	**0**
Appliance Service Rep Performance		

Performance 94.0% 94.4%
Penalty 0 0

On-Time Arrival

Performance 96.4% 96.0%
Penalty 0 0

Telephone Response Time (Regular)

Performance 83% 84.7%
Penalty 0 0

Telephone Response Time (Emergency)

Performance 92% 92.5%
Penalty 0 0

Employee Safety

Performance 8.21 6.9
Reward/(Penalty) $20,000 $280,000
The 1998 results were adopted by the Commission in Resolution G-3270.
Brief testimony was submitted in the 1998 SoCalGas BCAP A.98-10-012 on its PBR in order to comply with the midterm review requirement in D.97-07-054. However, the PBR had been in operation for less than a year at the time of the application, so little performance data was available at that time. No changes to the PBR were ordered in the Commission's BCAP decision, D.00-04-060.

II.D. Southwest Gas Alternative Ratemaking Mechanism

An "alternative ratemaking" approach was adopted for Southwest Gas in D.94-12-022 (A.94-01-021). Southwest Gas' Base Rate Mechanism replaces the traditional cost of capital proceeding with a rate of return (ROR) adjustment mechanism tied to movement in the 30-year Treasury Bond rate of at least 150 basis point. The original benchmark rate is equal to the average 30-year Treasury Bond rate for the three month period ending August 31, 1994. If the recorded monthly average 30-year Treasury Bond rate differs from the Benchmark by at least 150 basis points for three consecutive months, the ROR Adjustment mechanism requires Southwest to file an application with the Commission, within 60 days, addressing the issue of whether the Southwest's ROR should be modified to reflect the changes in utility's cost of capital. This adjustment has not been necessary since the mechanism was adopted.
During the term of the experiment (originally to be through Fall 1998) Southwest's margin rates were to remain at test year 1995 levels, excepting possibly due to adjustments as discussed above, or for attrition adjustments in the Northern California Division due to safety-related system improvements and funding for expansion area conservation programs. Attrition filings for 1996, 1997, and 1998 were also eliminated, except as discussed above for the Northern California Division.
Southwest Gas filed A.98-05-003 to request that its authorized ROR be maintained, even though its alternative ratemaking mechanism would normally have required it to file an application to modify the ROR. (Treasury Bond rates had barely fallen below the triggering benchmark.) In D.98-09-030, the Commission granted Southwest's request and ordered that further review of its ROR be integrated into its next GRC.
The Southwest Gas Rate Case cycle was originally extended from three to four years. A Southwest Gas GRC was scheduled to be filed in 1998 for a 1999 Test Year. In February 1999, Southwest Gas filed a Petition to Modify D.94-12-022. Southwest Gas requested

that the Commission extend the general rate case moratorium for Southwest to at least six years, i.e. at least through the year 2000, pending the resolution of other matters before the Commission. The Commission has not yet issued a decision on Southwest's Petition.

The "alternative ratemaking" approach for Southwest Gas does not include any adjustment for productivity, inflation, or customer growth, and does not include revenue sharing. Similarly, it does not include any rewards or penalties related to customer satisfaction, safety, or reliability.

Other than rate changes for the Northern California Division adjustments, there have been no changes in Southwest Gas' margin rates since they were adopted in D.94-12-022.

II.E. Pacific Gas and Electric Company Base Rate PBR Application

PG&E filed an application for a proposed base rate PBR in November 1998 (A.98-11-023). That proceeding was significantly delayed due to a delay in the issuance of a decision on the PG&E 1999 GRC. The decision was finally issued on February 17, 2000. However, in the GRC decision, D.00-02-046, the Commission suspended any action on the PG&E PBR update rule and revenue sharing component due to uncertainty about the validity of the revenue requirement it adopted as a starting point for a PBR. The Commission indicated it would consider proposals for quality of service incentives. In D.00-06-058, the Commission granted a PG&E Petition to withdraw its PBR application, but ordered PG&E to submit an application by September 1, 2000 proposing quality of service PBR standards and a permanent revenue sharing mechanism for OORs.

II.F. Sierra Pacific Base Rate PBR Application

Sierra Pacific filed an application for a proposed base rate PBR in December 1999 (A.99-12-041) to become effective January 2001. In D.00-05-004, the Commission found that Sierra Pacific's application was incomplete, but allowed Sierra to refile its application when the necessary supporting documentation was available. Sierra refiled its application on June 30, 2000. It is expected that the Commission will soon address Sierra's application.

III.
GAS PROCUREMENT INCENTIVE MECHANISMS

The Gas Procurement PBRs adopted by the Commission are generally intended to provide gas utilities with an incentive to minimize the cost of gas purchased for customers. Actual costs are compared to an established benchmark of costs, generally based on market prices for gas, and any excess costs or savings outside of a deadband are shared between shareholders and ratepayers. These gas procurement PBRs also serve to eliminate reasonableness reviews of gas procurement costs. Incentives have also been developed to employ storage withdrawals and injections to lower overall gas costs.

III.A. SDG&E Gas Procurement PBR

In D.98-08-038, the Commission adopted a modified gas procurement PBR for SDG&E to replace the gas PBR which had been in effect from August 1993 through July 1998. (The original SDG&E gas procurement PBR is described in Appendix 2.) The new SDG&E gas procurement PBR measures the utility's gas purchasing performance against a monthly market price benchmark by comparing actual procurement costs for gas supplies (1) in gas production basins to the basin indices and (2) at the California border to the border index.

III.A.1. SDG&E Gas Procurement PBR Benchmark Gas Cost Calculation

For the volumes which SDG&E purchases directly from southwest basins, using firm transportation to the California border, an "Average Index" is calculated using basin index data. The Average Index is calculated as the simple average of three published price indices for each basin. Firm volumetric charges are also added to the benchmark costs. SDG&E currently has 10 MMcf/d of firm interstate transportation capacity on El Paso pipeline. The reservation charges for this capacity is allowed in the benchmark costs, but no other firm interstate transportation reservation costs are allowed in benchmark costs.

For all other volumes, SDG&E calculates an average California Border Index using three published price indices for the California border price delivered to the Southern California Gas system. SDG&E had Canadian gas supply arrangements for several years, including firm interstate transportation contracts and gas supply contracts. For the purpose of calculating the benchmark indices, these volumes are treated as California border purchases. Any firm Canadian transportation reservation costs are not allowed as benchmark costs.

The monthly benchmark cost is the sum of 1) each average basin index and associated transportation cost, times the actual purchased gas volume from those basins, and 2) the California border index times the actual purchased volumes from all other sources.

III.A.2. SDG&E Gas Procurement PBR Deadband Calculation

A deadband is employed above the monthly benchmark cost. It is calculated as 2% of the monthly benchmark gas commodity cost less transportation costs, i.e. the benchmark gas costs less the firm volumetric transportation costs and El Paso reservation costs.

III.A.3. SDG&E Gas Procurement PBR Actual Costs

SDG&E's actual gas costs include its actual cost of gas purchases and other fees, surcharges, and offsetting revenues related to its gas purchases such as expenses, losses and gains for gas futures transactions, certain gas sales, and swaps.

III.A.4. SDG&E Gas Procurement PBR Shared Savings and Costs

When actual annual costs are below the benchmark annual costs, the savings are shared equally between shareholders and ratepayers. This essentially means that ratepayers pay shareholders a reward equal to 50% of the difference between actual costs and benchmark costs. When actual costs are above the deadband, shareholders pay 75% of the excess costs. This essentially means that 75% of the actually incurred excess costs would be refunded to ratepayers.

III.A.5. SDG&E Gas Procurement PBR Monitoring and Evaluation

SDG&E provides a monthly report of its performance to the Commission's ORA and the Energy Division. In addition, it provides an annual report of its performance 90 days after the completion of each annual period (August through July), including its calculation of any annual shared savings excess costs and associated rewards or penalties. ORA then issues its report on SDG&E's performance 75 days after the SDG&E annual report is filed. Final resolution of rewards and penalties is dealt with in an advice letter filed by SDG&E.

III.A.6. SDG&E Gas Procurement PBR Results

As of the date of this report, SDG&E has reported on one year of results under its new gas procurement PBR. (For five years of results under the original SDG&E gas procurement PBR, see Appendix 2.) SDG&E reported the following results in its November 12, 1999 compliance report filed with the Commission:

<u>SDG&E Gas Procurement PBR Results for August 1998 through July 1999</u>

Benchmark Costs: $210,341,727
Actual Costs: $207,749,199
Shared Savings: $2,592,528
Shareholder Reward: $1,296,264
(These results include $1.8 million in costs to reflect additional Canadian supply contract settlement costs and various other adjustments.) ORA issued its report on the above SDG&E results on April 26, 2000, and recommended a reduction in the shareholder reward to $418,610 to account for an exclusion of storage gains attributable to a third party sale of storage gas. ORA also found numerous SDG&E accounting errors during the course of its audit. The Commission has not yet acted on these recommendations.

Performance results under the original SDG&E gas procurement PBR are reported in Appendix 2.

III.B. SoCalGas Gas Cost Incentive Mechanism PBR ("GCIM")

The SoCalGas Gas Cost Incentive mechanism was adopted in D.94-03-076 (A.93-10-034). The mechanism was originally comprised of two separate components: one that measures performance for cost effective gas procurement efforts, the Procurement Incentive Mechanism (PIM), and one that rewards efficient gas storage performance for the core class, the Storage Incentive Mechanism (SIM). In D.97-06-061, the Commission eliminated the SIM for years beyond Year 3. The GCIM now includes almost all of SoCalGas' total gas purchases.[8] The GCIM adopted in D.94-03-076 originally had a three-year term. In D.97-06-061, the Commission extended the GCIM for another two years (i.e. through March 31, 1999), and adopted various GCIM modifications. In D.00-06-039, the Commission deferred judgment on whether to extend operation of the GCIM into Year 7, pending completion of an Energy Division evaluation report on the GCIM.

III.B.1. SoCalGas' PIM

The GCIM benchmark, against which SoCalGas' actual core gas purchases are measured, is based on a weighted combination of bids based on the New York Mercantile Exchange (NYMEX) index for gas futures, and Southwest gas price indices published in Natural Gas Intelligence and Inside FERC. The weighting depends on the number and
volume of NYMEX-related bids. (Every month SoCalGas solicits bids from suppliers with prices set at a basis in relation to the NYMEX gas futures price for the following month.) The southwest gas price portion is itself a weighted combination of San Juan and Permian basin prices on El Paso and Transwestern pipelines. The weighting of the southwest gas price portion depends on the actual volumes purchased by SoCalGas from these sources. A "tolerance band" (i.e. a "deadband") allows for variance in service reliability and supply security. The tolerance band was 4.5% above the benchmark for the first year of the GCIM, and 4% for Years 2 and 3. The Commission adopted a 2% tolerance band above, and a 1/2% tolerance band below the benchmark budget for Years 4 and beyond, in D.97-06-061. Firm volumetric interstate transportation charges are included in the benchmark budget for basin purchases.

In D.97-06-061 SoCalGas was also permitted to include border purchases in its benchmark costs. Up to 10% of its annual demand may be purchased at the border or via incremental interstate capacity. A monthly border index in proportion to the volumes purchased is included in the benchmark price.

D.97-06-061 allows SoCalGas "hub" revenues to be included as a credit to the GCIM actual cost. SoCalGas is also allowed to include gains and losses from gas futures transactions and revenues from gas sales in its calculations of GCIM actual costs.

SoCalGas' core interstate pipeline demand charges on El Paso and Transwestern (for 743 MMcfd and 301 MMcfd, respectively) less costs recovered for brokered capacity are included in both the benchmark cost and actual costs. For the period prior to Year 4, Transwestern San Juan Lateral capacity costs were not included in benchmark costs. However, actual purchases made on the San Juan Lateral (SJL) were measured against a Permian Basin price index. For later GCIM years, D.97-06-061 allowed San Juan Lateral capacity costs in the benchmark costs, and SJL purchases are to measured against a San Juan Basin price index.

Actual costs outside the PIM deadband are shared equally between ratepayers and shareholders. Essentially, shareholders pay 50% of the costs above the upper end of the deadband, and are rewarded by 50% of the difference between actual costs and the lower end of the deadband.

III.B.2. SoCalGas' SIM

As noted above, the SIM was eliminated for years beyond Year 3, but it is described here for convenience. The Storage Incentive Mechanism portion of the GCIM compared SoCalGas' actual annual total purchased gas cost to an annual benchmark. The difference between the annual benchmark and the actual total purchased gas cost--whether positive or negative--was shared equally between ratepayers and shareholders. Like the PIM, the SIM was designed to reduce the cost of gas by encouraging SoCalGas to time its storage injections and withdrawals so that it may take advantage of seasonal gas price variations.

The NYMEX natural gas futures market was the price mechanism used for purposes of month-to-month price comparisons (spread) under the Storage Incentive Mechanism. The spread between two specific months during the Basic Injection or Swing Withdrawal period was used to determine if shifts in injections/withdrawal decisions were to be made. If the futures price spread between two specific months was 10% or greater, shifts in injection/withdrawal decisions were supposed to be made.

In determining whether the requisite 10% spread exists, the futures price of a distant month must have been at least 10% greater/less than the near month against which it is being compared. Volume shifts were made on the basis of the largest percentage shift. In the case of equal spreads of at least 10%, the first available opportunity was to be utilized to make a Storage Incentive Mechanism volume shift. To capture the price spread advantage for the Storage Incentive Mechanism, SoCalGas used financial hedging opportunities on the futures market. The mechanism also included operating constraints which assured that enough storage reserve existed to accommodate peak day demands and unplanned outages on the transportation and storage system.

III.B.3. SoCalGas GCIM Monitoring and Evaluation

Under the monitoring and evaluation ("M&E") component of the GCIM, SoCalGas provides detailed monthly reports regarding SoCalGas' monthly core procurement activity, including purchases, sales, futures position, and swaps. In addition, this component requires SoCalGas to: (1) provide documentation on excess core gas sales to assure that the utility is not selling core gas in order to increase its sales and thereby decreasing its unit cost, and (2) to track any gas purchases that occur under the pricing anomaly which occurs when two benchmark prices are not calibrated to actual prices (see D.94-03-076, pg. 10 for specific details).

SoCalGas annually submits an application to the Commission on June 15th which reviews the operation of the GCIM during the previous GCIM Year, from April through March, and requests the approval of the annual reward or penalty which results from the operation of the GCIM. ORA then reviews SoCalGas' operations and calculations, performs an audit, and makes its own recommendations to the Commission.

In D.00-06-039, the Commission ordered the Commission's staff to conduct "a full independent review of GCIM which will go to the merits of the program itself and not duplicate ORA's annual audits." The evaluation report is due by January 1, 2001. The Commission deferred judgment on whether to extend operation of the GCIM into Year 7 pending completion of the evaluation report.

III.B.4. SoCalGas GCIM Results

Table 5
SoCalGas GCIM Results ($1000)

	MMMBtu Purchased	PIM Benchmark Costs	PIM Actual Costs	PIM Reward/ (Penalty)	SIM Reward

Year 1	276,627	$567,448	$568,566	0	$106
Year 2	242,565	$448,713	$442,313	$ 3,200	$ 67
Year 3	242,637	$680,062	$658,876	$10,593	$171
Year 4	252,219	$672,132	$665,307	$ 2,039	NA
Year 5	288,353	$649,295	$631,138	$ 7,733	NA
Year 6*	*	$1,061,264	$1,037,113	$9,760	NA

*Year 6 results have not been adopted as of the date of this report. Year 6 volumes aren't yet available.

III.C. PG&E Post-1997 Core Procurement Mechanism ("CPIM")

Although a PG&E Core Procurement Incentive Mechanism (CPIM) had been proposed as early as December 1994, PG&E's original CPIM was not adopted until the Commission issued D.97-08-055, on the PG&E Gas Accord (A.96-08-043). The PG&E CPIM was different for the period prior to 1/1/98 compared to the CPIM beginning 1/1/98.[9] The mechanism applicable to the period after 1/1/98 is intended to be effective through December 31, 2002, but will undergo "significant review" after its initial three years of operation.

For the period after January 1, 1998, the CPIM reflects the unbundling of the PG&E intrastate transmission system, the assignment of core interstate contractual capacity rights effective July 1, 1997, and the December 31, 1997 expiration of PG&E's contract with El Paso Natural Gas Company for firm interstate transportation capacity.

The current CPIM is made up of two components: 1) the fixed transportation cost component, which includes both interstate and intrastate capacity reservation costs; and 2) the variable cost component, which covers commodity costs and volumetric transportation costs. The mechanism also addresses the reasonableness of PG&E's storage costs and operations through a daily-load calculation and the inclusion of storage costs. In addition, an alternative benchmark may be employed if certain "extraordinary events" occur which are beyond PG&E's control.

III.C.1. PG&E CPIM Benchmark Costs

<u>Fixed Interstate Transportation Cost Component</u>

Reservation charges associated with the following interstate capacity are included in both the benchmark and actual cost portions of the mechanism:

Canadian Access: 610.0 Mdth/d on PGT, 586.8 Mdth/d on ANG and 596.4 Mdth/d on NOVA a full ABR.

Southwest Access: No interstate demand cost component in the benchmark. Interstate demand charges associated with PG&E's Transwestern reservation 150 Mdth/d are included as a cost of gas only to the extent it is usable based on PG&E's need to purchase gas in excess of its California and PGT capacity.

The capacity amounts are reduced based on the size of the core transportation program as provided in PG&E's Application 96-09-028, *Treatment of Interstate and Canadian Capacity for Core Transportation Customers Effective January 1, 1998.*

<u>Intrastate Capacity Costs</u>

Reservation charges associated with the following intrastate capacity will be included in both the benchmark and actual-cost portions of this mechanism:

Malin-to-On-System: 610.0 Mdth/d (600 MMcf/d) year-round at full annual-firm ABR (vintage price)

Topock-to-On-System: 154.5 Mdth/d (150 Mmcf/d) year-round at full annual-firm ABR, plus 154.5 Mdth/d (150 Mmcf/d) November and March at full seasonal-firm ABR and 463.5 Mdth/d (450 Mmcf/d) December through February at full seasonal-firm ABR

California-to-On-System: 50 Mdth/d (50 Mmcf/d) year-round at full annual-firm ABR.

As provided in the Gas Accord, these intrastate capacity holdings may be revised through the BCAP process, but no earlier than the year 2000. Core transport agents may elect to utilize a pro-rata share of this capacity. To the extent that they do not elect to do so, the costs and use of that capacity will be included in the Post-1997 CPIM

Additional Capacity Charges

Charges for firm or interruptible interstate and intrastate pipeline capacity incurred in addition to those described as above will be included as a gas cost under the CPIM, with no additional allocation of benchmark dollars. No demand charges associated with PG&E's existing Transwestern reservation will be allowed in the gas cost portion of the Post-1997 CPIM except as otherwise noted.

Variable Cost Component

The variable cost component is composed of gas cost indices (inclusive of all volumetric transportation costs to the citygate) at the expected points of purchase multiplied by the quantity of gas expected to be purchased at each index point on a daily basis. The benchmark will be developed using an assumed purchasing sequence, monthly and daily price indices, and a daily calculated purchase volume which reflects an adjustment for a planned amount of storage injection or withdrawal.

Purchasing Sequence

During the summer months (April through October), the daily benchmark shall assume the following sequence of gas purchases: (I) California purchases; (ii) northern purchases transported on PG&E's 610 Mdth/d (600 Mmcf) of firm capacity through Malin (adjusted based on load and capacity shifted to core transport agents); (iii) Topock border purchases transported on the core's firm intrastate capacity; and (iv) Topock border purchases transported on as-available intrastate capacity.

During the winter months (November through March), the daily benchmark will assume the following sequence of gas purchases: (I) California purchases; (ii) northern purchases transported on ninety-five percent (95%) of PG&E's firm capacity through Malin adjusted based on load and capacity shifted to core transport agents (610 Mdth/d x .95 = 579 Mdth); (iii) Topock border purchases transported on all but 100 Mdth/d of the core's firm intrastate capacity; (iv) northern purchases transported on the remaining five percent (5%) of PG&E's firm capacity through Malin; (v) Topock border purchases transported on the remaining 100 Mdth/d of the core's intrastate capacity; and (vi) Topock border purchases transported on as-available intrastate capacity.

In the event of a basin-price reversal where firm Topock supplies are less expensive than firm Malin supplies (based on the index value at Topock and AECO C plus respective volumetric costs to the citygate), the benchmark will be based on a revised sequencing assumption as follows: (I) California purchases; (ii) Topock border purchases transported on the core's firm intrastate capacity; (iii) northern purchases transported on PG&E's 610 Mdth/d (600 Mmcf) of firm capacity through Malin (adjusted based on load and capacity shifted to core aggregation); and (iv) Topock border purchases transported on as-available intrastate capacity. The change in the benchmark sequence resulting from a basin-price reversal will transition over a three-month period: during the first month of a basin-price reversal the benchmark will sequence thirty-three percent (33%) of the firm Topock capacity before the Malin capacity; in the second month, the benchmark will sequence sixty-six percent (66%) of the firm Topock capacity before Malin capacity; and there will be a one-hundred percent (100%) adjustment for the third month. A similar thirty-three percent (33%)-percent-per-month transition will be used if prices shift in the opposite direction at any point in time.

Index Composition

The PG&E CPIM will employ published gas indices for Canadian, southwest, and California volumes. The main Canadian gas index is the Canadian *Enerdata* 30-day baseload index at AECO-C plus NOVA, ANG, PGT and Malin-to-on-system volumetric costs.

The southwest gas index will be the Topock bidweek index as reported in *Natural Gas Week* for all benchmark volumes assumed to flow within the core's firm Topock capacity reservation. The average price for the specific day as shown in *NGI's Daily Gas Price*

Index published by Natural Gas Intelligence for the "Southern California Border" delivery point plus the Topock-to-on-system tariff as-available cost will be used for southwestern volumes assumed to flow in excess of the core's firm Topock capacity reservation on a given day.

The California price index will be the Topock bidweek index as reported in *Natural Gas Week* plus Topock-to-on-system volumetric costs to the citygate. ORA and PG&E will meet in the second quarter of 1998 to determine if a change is warranted in the California index based on the status of the traditional California contracts and current Fair Market Price.

In addition, a series of backup indices will be used in the event that the primary publications fail to publish the required indices.

<u>Daily Load Calculation</u>

The determination of the weighting components for the benchmark will be calculated each day, using the daily core portfolio load, the firm in-state capacity reservation quantities, and an allocation of storage withdrawal or injection gas. The preliminary core portfolio load will be the actual or projected core portfolio customer usage as determined by the Core Load Forecast model, the daily pipeline operations report, or other suitable mechanism as agreed between PG&E and ORA. This usage number will then be adjusted to account for normal storage expectations.

<u>Specific Benchmark</u>

The calculated daily benchmark is reached using the capacity sequence described above. The resulting calculated volume at each purchase point will be multiplied by its respective index price, and the results will be totaled to create that day's volumetric benchmark cost. The daily amounts will be added together to create the monthly volumetric benchmark dollars.

III.C.2. PG&E CPIM Gas Costs

All costs associated with the purchase of natural gas can be included as a cost of gas under the mechanism. Such costs shall include gas commodity costs; capacity reservation charges (except Transwestern demand charges as limited below); volumetric transportation costs; liquids extraction costs; capacity acquisition or brokering costs; and pipeline imbalance, diversion or other penalties. These costs may or may not occur at the same places and at the same times as assumed by the benchmark sequence.

<u>Transwestern Demand Charges</u>

Transwestern demand charges at the full as-billed rate may be included the actual costs on any day only up to the amount that the daily assumed benchmark sequence includes Topock volumes, to a maximum of 150 Mdth per day. When the Topock purchase volume assumed in the sequence is less than 150 Mdth per day, demand charges associated with the Transwestern capacity indicated as not needed will not be included as an actual cost of gas considered under this incentive mechanism.

III.C.3. PG&E Tolerance Band

The allowed monthly benchmark dollars and actual costs will each be totaled over the annual CPIM period and compared to determine PG&E's performance. The tolerance band will have an upper limit, above the aggregate benchmark, equal to the total benchmark dollars (fixed and variable components) plus an additional amount equal to two percent (2%) of the variable component of the benchmark, and a lower limit, below the aggregate benchmark, equal to one percent (1%) of the variable component of the benchmark. To the extent that actual costs fall within the tolerance band they will be paid by ratepayers and there will be no shareholder penalty or reward.

If actual costs should fall outside the tolerance band, there will be a 50/50 sharing between ratepayers and PG&E shareholders of the gains or losses incurred.

III.C.4. PG&E Alternative Benchmark

An alternative benchmark is employed in the event that extraordinary circumstances prevent PG&E from meeting core demand. During such events, the utility may be forced to divert supplies from noncore to core use, either through economic arrangements or through mandatory diversion. To the extent that these extraordinary circumstances require diversions or other highly unusual measures to provide for core supply reliability, the resulting costs can be evaluated against an alternative benchmark based on a citygate index.

Alternative Benchmark Index

All voluntary diversion (through deals to buy others' supplies) and involuntary diversion costs made necessary by PG&E's obligation to serve core needs will be compared initially to a proxy burner-tip index equal to the high value of the daily Topock index range plus the Topock-to-on-system as-available rate. The proxy rate will be replaced when a PG&E on-system or citygate index is available.

Specific Conditions for Use of Alternative Benchmark

This alternative benchmark calculation explicitly recognizes the possibility of economic or mandatory diversion of supplies from noncore use to core use by adding a citygate benchmark whenever the following conditions are met:

(1) all firm transportation rights contracted to core customers are fully nominated;

(2) all firm withdrawal rights contracted to core customers are fully nominated, and

(3) all as-available transmission capacity and storage withdrawal capacity allocated to core customers is fully nominated, and additional supplies are still needed.[10]

Under these conditions, PG&E may elect to use the alternative benchmark. PG&E will notify ORA of such an election within seven days of the event's occurrence. Gas supplies received through (1), (2), and (3) above will be included under the regular benchmark. Any gas quantity required in excess of those volumes will qualify for alternative benchmark treatment. PG&E may also request use of the alternate benchmark for costs associated with *any* extraordinary event or condition. If ORA does not agree to such use, PG&E has the right to file with the Commission and have the costs associated with the extraordinary event or condition in a mini-reasonableness review.

Tolerance Bands and Sharing

There is no tolerance band for the alternate benchmark. Actual cost savings or overruns, relative to the benchmark, will be shared ninety-five percent (95%) by ratepayers and five percent (5%) by shareholders.

Termination of Alternative Benchmark

In recognition that the market conditions that cause or occur during extraordinary events can vary widely from expectations, certain qualifying provisions allow for the potential termination of use of the alternative benchmark.

III.C.5. PG&E Monitoring and Evaluation

PG&E provides information on CPIM activity during the year, primarily through monthly CPIM reports and an annual report outlining cost savings, rewards, or penalties, and related pertinent information.

ORA will review, evaluate and audit the annual CPIM results to assure the program is functioning as intended. PG&E and ORA will meet throughout the course of the Post-1997 CPIM to determine if modifications to the mechanism are necessary. Approval of CPIM rewards or penalties is accomplished through the advice letter process.

After three years of operation, the CPIM will undergo a significant review to ensure that the mechanism appropriately reflects the prevailing market structure.

III.C.6. PG&E CPIM Results

The post-1997 CPIM became effective on January 1, 1998. However, since PG&E's storage activities are much different during the winter (November through March) compared to summer operations (during April through October), the first CPIM period ran from January through October 1998. Subsequent CPIM years run from November through October.

Results for the period from January to October 1998 were filed by PG&E on January 15, 1998. Those results were reviewed by ORA in a report dated May 17, 1999, and later approved by the Commission on November 16, 1999 via advice letter 2190-G. PG&E's results for the period November 1998 through October 1999 were filed on January 31, 2000. ORA has not yet completed its review of these latter results. PG&E's post-1997 CPIM results are shown below. For the results of PG&E original CPIM see Appendix 2.

Performance Results for the Post-1997 PG&E CPIM

	Approved 1/1/98 - 10/31/98	Reported 11/1/98 - 10/31/99
Benchmark Costs	**$496.9 million**	**$817.4 million**
Actual Costs	$492.5 million	$822.0 million
Below/(Above) Tolerance	$0.4 million	$0
Shareholder Reward/ (Penalty)	$0.2 million	$0

IV. INCENTIVE MECHANISMS FOR OTHER OPERATING REVENUES

IV.A. SCE's Gross Revenue Sharing Mechanism for Certain Other Operating Revenues

Southern California Edison Company (SCE) filed A.97-06-021 requesting authorization to adopt a gross revenue sharing mechanism[11] (GRSM) for certain other operating revenues (OOR). D.99-09-070 conditionally adopted a settlement between SCE and the Office of Ratepayer Advocates (ORA). The settlement's GRSM for OOR would replace the PBR mechanism that the Commission already has in place for that share of SCE's revenues derived from non-tariffed products and services. The GRSM would apply to all of SCE's OOR. The effective date for SCE's GRSM is September 16, 1999.

IV.A.1. Background

Due to the restructuring of the California electric industry, utility distribution companies (UDCs) are considering how to generate additional revenues from their assets (especially non-tariffed products and services). The Commission has demonstrated a policy of providing the UDCs with incentives to use its underutilized property for other productive purposes without interfering with their operation or service to its customers.[12]

Past rate PBRs encouraged the UDCs with incentives to reduce cost through greater productivity, while maintaining the quality of electric service to its customers. The PBR does not generally take into consideration the utilization of the UDCs' assets.

D. 99-09-070 states, "The overall concept of a revenue sharing mechanism for revenues from non-tariffed products and services is in the public interest because it provides the utility with incentives to use utility property for other productive purposes without interfering with the utility's operation or affecting service to utility customers."[13]

Prior to D.99-09-070, SCE had proposed, and the Commission had adopted, incentive mechanisms on a piecemeal basis for revenues associated with various, specific assets. For example, OOR was collected in the Telecommunication Lease Revenue (TLR) Memorandum Account, the Secondary Land Use Revenue (SLUR) Memorandum Account, and the PBR (adopted in the D.96-09-092). With the adoption of D.99-09-070, instead of having different OOR accounts, SCE consolidated these accounts into a single GRSM.

OOR entries into the TLR and SLUR Memorandum Accounts will cease[14] on September 16, 1999 (the effective date of D.99-09-070). Recorded revenues will be split on a 50/50 basis between SCE's shareholders and ratepayers. Effective September 16, 1999, the OOR from these two memorandum accounts[15] will be reflected in the GRSM adopted in D.99-09-070.

IV.A.2. SCE's OOR Mechanism

The incremental OOR above a threshold amount and related incremental costs associated with the GRSM will be excluded from the calculation of the recorded PBR distribution return on equity. The settlement's GRSM for OOR would replace the PBR mechanism for that share of SCE's revenues derived from non-tariffed products and services.

The adopted OOR mechanism covers "Non-tariffed Products and Services". Currently, SCE has approximately 26 different types of "Non-tariffed Products and Services." A few examples are the Use of General Facilities, Secondary Use of Transmission Right-of Ways and Land, Use of Communications and Computing Systems, and Material Procurement and Purchasing Services.[16] There are two sharing allocation modes - "active" and "passive" applied to OOR activities and revenues.

The sharing allocation modes are defined as:

· "active" if it involves a total incremental shareholder investment[17] of $225,000 or more (either on a one-time basis or within a 12-month period). This $225,000 threshold is not to include capital-related costs, labor, and other expenses properly charged to the utility ratepayers. Allocation of the "active" Incremental OOR is on a 90%/10% (shareholder/ratepayer) basis.

· "passive" if it involves a total incremental shareholder investment of less than $225,000. Allocation of the "passive" Incremental OOR is on a 70%/30% (shareholder/ratepayer) basis.

The approved sharing allocation mode percentages for "active"[18] (90/10) and "passive"[19] (70/30) were based upon prior Commission decisions.

IV.A.3. Revenues Not Applicable To OOR

The gross revenue-sharing mechanism is intended to be applied only to OOR derived from the enhanced utilization of utility assets. The following OOR categories are not included:

· OOR from tariffs, fees and charges regulated by the Commission or Federal Energy Regulatory Commission (FERC) - These revenues are from tariffs, fees and charges (e.g., service establishment and late payment fees, reconnection charges, added facilities, transmission service for third parties) that are rate-regulated by either the Commission or FERC.

· OOR subject to other established ratemaking procedures or mechanisms - such as decommissioning trust fund earnings, labor mark-up and facility charges for affiliate transactions, and gains or losses on the sale of utility property.

· OOR subject to the Demand-Side Management (DSM) Balancing Account

IV.A.4. Incremental OOR

Incremental OOR[20] is the recorded gross revenue derived from non-tariffed products and services subject to the GRSM that exceeds an OOR Threshold during each calendar year.

The annual calendar year OOR Threshold is determined by the amount of the OOR from non-tariffed products and services reflected as a revenue credit in SCE's most recent General Rate Case (GRC). SCE is expected to file a 2002 Test Year GRC in the latter half of 2000. The current OOR Threshold is $16,671,389.[21] (The $16.7 million of OOR becomes a "threshold" amount, above which any Incremental OOR will be shared between customers and shareholders based on the GRSM.)

SCE will maintain a monthly Gross Revenue Sharing Tracking Account (GRSTA) beginning on January 1st of each calendar year. The applicable month's recorded calendar year-to-date gross revenues from non-tariffed products and services subject to the GRSM are subtracted from the annual calendar year OOR Threshold. If the difference is a positive result, then no entries are made to the GRSTA for the month since the OOR Threshold has not been reached. If the result is a negative amount, then the OOR Threshold [22] has been reached and the recorded Incremental OOR must be allocated proportionally between the "active" and "passive" non-tariffed products and services monthly revenues.

The recorded monthly Incremental OOR above the Threshold will be allocated to the shareholders and ratepayers by applying the appropriate Active Sharing Allocation or Passive Sharing Allocation percentages. The ratepayers' share of the allocations is credited to the GRSTA. The shareholders allocation of the Incremental OOR is not recorded in the GRSTA.

SCE will transfer the balance in the GRSTA[23] to the Electric Deferred Refund Account (EDRA) at the end of each calendar year. The EDRA balances will be refunded to the ratepayers annually. After the balance of the GRSTA has been transferred to the EDRA, beginning January 1st of the calendar year, the balance in the GRSTA will be reset to zero.

IV.A.5. Affiliates

Rule VII of the Affiliate Transaction Rules under which energy utilities can offer non-tariffed products and services has not been modified by the settlement. The conditions are still applicable to both the utilities and their affiliates.

The Energy Division must analyze new and reclassified types of non-tariffed products and services to ensure compliance with the Affiliate Transaction Rules. If the type of non-tariffed products and services is not in compliance, the Energy Division will recommend that the Commission reject the new or reclassified proposal. [24]

IV.A.6. Revisions to List of Approved Non-Tariffed Products and Services

Any new category of products or services will be considered to be "passive." In order to reclassify any existing category from "passive" to "active" or to classify a new category initially as "active", SCE must do the following:

· File an advice letter with the Energy Division (ED) documenting that the product or service involves incremental shareholder investment of at least $225,000 (either on a one-time basis or within a 12-month period).

· Meet with ORA to discuss the proposed advice letter and classification of the new category.

Only four advice letters proposing a reclassification can be filed in any calendar year. All advice letters shall be subject to General Order 96-A or its successor.

IV.B. PG&E Interim OOR Mechanism

IV.B.1. Background

Under PG&E's 1996 and 1999 General Rate Case (GRC), revenues from non-tariffed uses of utility assets are included in the forecast of "Other Operating Revenues" (OOR). The forecasted amount of OOR reduces the total revenue requirement, offsetting the amount of revenue that must be collected from the ratepayers through rates. [25] The shareholders receive the benefit of any revenues in excess of the GRC forecast until it is updated in the next GRC.

In A.98-05-007, PG&E requested authorization to adopt a revenue sharing mechanism and other prerequisites for <u>new</u> non-tariffed products and services. D.99-04-021 adopted PG&E's proposal in A.98-05-007 on an interim basis. The NRSM would apply to new non-tariffed products and services categories generated after December 17, 1997.

PG&E was ordered to file supplemental testimony in A.98-11-023 describing a permanent revenue sharing mechanism for new non-tariffed products and services. (On

November 12, 1998, PG&E filed its PBR application (A.98-11-023).) On March 30, 2000, PG&E filed a petition to withdraw A.98-11-023. PG&E requested that the Commission, in its decision granting this petition, would allow the interim net revenue sharing mechanism approved in D.99-04-021 to continue in effect until further order of the Commission. D.00-06-058 granted PG&E's requests, but also ordered PG&E to propose a permanent mechanism in an application to be filed September 1, 2000.

IV.B.2. PG&E's Net Revenue Sharing Mechanism for New Non-tariffed Products and Services

PG&E filed A. 98-05-007 requesting authorization to adopt a net revenue sharing mechanism (NRSM) and other prerequisites for new non-tariffed products and services (NTP&S) pursuant to Rule VII of the Affiliate Transaction Decision (D. 97-12-088). In D.97-12-088, the Commission approved the Affiliate Transaction Rules governing the relationship between California's energy utilities and their affiliates. These rules were revised in D.98-08-035. Rule VII. F requires each utility to file an advice letter describing its existing products and services (both tariffed and non-tariffed) currently offered by January 30, 1998.

On January 30, 1998, PG&E filed Advice Letter (AL) 2063-G/1741-E[26] as required by D. 98-08-035. The AL contained the current list of existing products and services (both tariffed and non-tariffed) being offered by PG&E.

On September 8, 1998 and April 1, 1999[27], AL 2063-G/1741-E was amended.[28]

PG&E proposed a revenue-sharing mechanism that treats all new NTP&S categories the same, regardless of the nature of the product or services being offered, or PG&E's mode of participation. Positive net revenues from these new NTP&S categories will be divided equally between ratepayers and shareholders.

IV.B.3. PG&E's Net Revenue Sharing Mechanism

The adopted NRSM will apply to new non-tariffed products and services categories developed after December 17, 1997.[29] The shareholders and ratepayers will share the positive after-tax net revenues on a 50/50 basis.[30] After-tax net revenues are defined as gross revenues, less incremental costs of new NTP&S and taxes.

All incremental costs[31] of developing, marketing and offering the new NTP&S will be allocated to these NTP&S. Incremental cost will include both recurring and non-recurring costs attributable to the product or service.[32]

PG&E will track the revenues and incremental costs from new categories of NTP&S using accounting entries separate from other utility operations.[33] Periodic Reports of Non-Tariffed Products and Services[34] will include the report of incremental costs and revenues for each new category of NTP&S. Also, the Periodic Reports will include the amounts of shareholder and ratepayer positive net revenue allocations for the relevant period of the report.

IV.B.4. Affiliates

> D. 99-04-021 has not modified Rule VII of the Affiliate Transaction Rules under which energy utilities can offer non-tariffed products and services. The conditions are still applicable to both the utilities and their affiliates.

The Commission, through Advice Letters, must analysis and review new categories of non-tariffed product and services to ensure compliance with the Affiliate Transaction Rules.

APPENDIX 1
CHRONOLOGY OF PBR PROCEEDINGS

SDG&E Original Base Rate PBR

<u>December 3, 1992</u>: Commission issues SDG&E 1993 Test Year GRC Decision 92-12-019

<u>October 16, 1992</u>: SDG&E files A.92-10-017, proposing Base Rate PBR
<u>August 3, 1994</u>: Commission adopts Base Rate PBR in D.94-08-023
<u>August 18, 1994</u>: SDG&E files Advice Letter 922-E/931-G, transmitting tariff language (no resolution)
<u>August 26, 1994</u>: SDG&E files Advice Letter (AL) 924-E/932-G setting forth 1994 PBR revenue requirements (no resolution)
<u>October 17, 1994</u>: SDG&E files AL 927-E/936-G, setting forth 1995 PBR authorized revenue requirement
<u>December 21, 1994</u>: Commission issues Resolution E-3401, approving 1995 PBR authorized revenue requirement
<u>April 26, 1995</u> : Commission issues D.95-04-076, in SDG&E ECAC A.94-10-023, incorporating 1994 and 1995 electric PBR authorized revenue requirement in electric rates
<u>May 15, 1995</u>: SDG&E files AL 947-E/966-G, 1994 Performance Summary Report
<u>July 19, 1995</u>: Commission adopts 1994 Performance Summary Report, Resolution E-3416
<u>July 25, 1995</u>: SDG&E files AL 952-E/978-G to adjust 1995 PBR revenue requirement to incorporate 1994 shared revenue (no resolution)
<u>October 16, 1995</u>: SDG&E files AL 960-E/990-G, which sets forth 1996 PBR authorized revenue requirement.
<u>December 20, 1995</u>: Commission adopts 1996 PBR authorized revenue requirement in Resolution E-3434
<u>January 19, 1996</u>: SDG&E files AL 979-E, revises 1996 PBR revenue requirement (no resolution)
<u>April 12, 1996</u> : SDG&E files AL 983-E, implements SONGS ratemaking, revises PBR authorized revenue requirement (no resolution)
<u>May 15, 1996</u>: SDG&E files AL 986-E/1012-G, transmitting 1995 PBR Performance Summary Report
<u>June 6, 1996</u>: Commission issues D.96-06-033, SDG&E 1996-97 ECAC, incorporating 1996 PBR electric revenue requirements in rates. (Electric rates frozen as of 1/1/97 due to AB 1890 at rates set by D.96-06-033.)
<u>June 19, 1996</u>: Commission issues D.96-06-055, adopting an SDG&E MICAM
<u>October 15, 1996</u>: SDG&E files AL 1002-E/1032-G, setting forth 1997 PBR revenue requirements
<u>December 20, 1996</u>: Commission issues D.96-12-077, acknowledging potential conflict between PBR reward/penalty and CTC headroom, indicates that this issue should be addressed in SDG&E PBR midterm review
<u>December 1996</u>: SDG&E Midterm Review commences.
<u>December 20, 1996</u>: Commission adopts 1997 PBR revenue requirements, Resolution E-3401 (The Commission has apparently assigned the same resolution number to two different resolutions. See above resolution which approved 1995 authorized revenue requirement.)
<u>March 1997</u>: Midterm Review Report issued by Vantage Consulting
<u>April 15, 1997</u> : SDG&E files advice Letter 1030-E/1049-G, proposing a decrease in revenue requirements due an error in tax rates used for 1997 revenue requirement.
<u>April 23, 1997</u>: Commission issues D.97-04-085, suspending the requirement that SDG&E file a 1999 Test Year GRC. The suspension is for 120 days to allow parties in midterm review to reach settlement. A cost-of-service study may be required with SDG&E's distribution PBR application, due in December 1997.
<u>May 15, 1997</u>: SDG&E files Advice Letter 1036-E/1051-G, transmitting 1996 PBR Performance Summary Report.
<u>August 14, 1997</u>: SDG&E files AL 1041-E, to update distribution revenue requirement, in compliance with D.97-08-056
<u>September 3, 1997</u>: Commission issues D.97-09-052, which eliminates electric price performance comparison from base rates PBR

October 10, 1997: SDG&E files Advice Letter 1050-E/1070-G for 1998 PBR revenue requirement for electric distribution and gas department.
December 3, 1997: Commission approves 1998 electric distribution and gas department PBR revenue requirement in Resolution E-3509
December 3, 1997: Commission issues D.97-12-041, which ends the midterm evaluation, orders a 1999 cost-of-service showing in SDG&E's new PBR application, retains the PBR revenue sharing and non-price incentives for 1998, and suspends the requirement for a formal "final" evaluation of the PBR
December 16, 1997: Commission approves 1996 PBR rewards, but orders SDG&E to recalculate revenue sharing, in Resolution E-3512
May 15, 1998: SDG&E files AL 1095-E/1097-G transmitting 1997 PBR Performance Summary Report.
December 17, 1998: Commission adopts Resolution E-3562, which adopts quality of service rewards and penalties for 1997, but orders SDG&E to recalculate revenue sharing amounts.
December 31, 1998: Original SDG&E Base Rate PBR terminates.
May 15, 1999: SDG&E files AL 1166-E/1148-G transmitting 1998 PBR Performance Summary Report.
November 4, 1999: Commission approves 1998 PBR Performance Report in Resolution E-3638

SDG&E New Base Rate PBR

January 16, 1998: SDG&E files an electric distribution and gas department PBR application, A.98-01-014, including a 1999 cost of service study.
December 1998: Commission issues D.98-12-038 which adopts a 1999 cost of service
revenue requirement. This provides the starting point rates for the new PBR.
May 13, 1999: Commission issues D.99-05-030 which adopts a new base rate PBR for SDG&E electric distribution and the gas department.
May 24, 1999: SDG&E files AL 1170-E/1152-G implementing tariff language for the new PBR. SDG&E also files AL 1151-G to record gas-related rewards, penalties and revenue sharing amounts in the RPBA
June 10, 1999: SDG&E files AL 1171-E/1154-G to adjust revenue requirements due to divestiture of South Bay and Encina Power Plants and the sale of the South Bay Service Center Facility, in compliance with D.98-12-038
June 17, 1999: UCAN and NRDC file an Application for Rehearing of D.99-05-030
September 22, 1999: SDG&E files AL 1168-G to terminate the Gas Fixed Cost Account, in compliance with D. 99-05-030
October 1, 1999: SDG&E files annual advice letter AL 1193-E/1169-G to adjust electric distribution and gas rates using PBR adjustment formula for 2000
October 13, 1999: SDG&E files AL 1195-E to adjust electric distribution rates to return to customers an overcollection in the Tree-Trimming Balancing Account, in compliance with D.98-12-038
November 4, 1999: Commission issues D.99-11-029 which denies UCAN/NRDC application for rehearing of D.99-05-030, but makes modifications
December 3, 1999: SDG&E files AL 1203-E to make a downward adjustment to its 2000 electric distribution rates due to an error originating in 1999 rate calculations
February 17, 2000: SDG&E files AL 1215-E to return revenue overcollected in 1999 electric distribution rates due to the error originating in 1999 rate calculations
March 15, 2000: SDG&E files AL 1221-E/ 1192-G to submit 1999 PBR Performance Report
March 29, 2000: SDG&E files A.00-03-062 to retain the MICAM at least through 2002
June 21, 2000: SDG&E files AL 1221-E-A/1192-G-A to correct 1999 PBR performance report

June 30, 2000: SDG&E files A.00-06-051 to propose PBR evaluative criteria

SDG&E New Base Rate PBR Upcoming Events

2000-2001: SDG&E PBR midterm review

October 2000: SDG&E files rate update for 2001

February 2001: SDG&E files 2000 performance report

October 2001: SDG&E files rate update for 2002

December 2001: SDG&E files 2003 cost-of-service application

SCE Distribution PBR

December 23, 1993: SCE files A.93-12-029 proposing Transmission & Distribution (T&D) PBR

September 20, 1996: Commission adopts T&D PBR in D.96-09-092

October 22, 1996: SCE files Advice Letter 1191-E, which transmitted PBR tariff language

November 1, 1996: TURN files Application for Rehearing of D.96-09-092

December 20, 1996: Commission adopts SCE PBR tariff language, with Resolution E-3478

Summer, fall, 1997: Workshops conducted

November 3, 1997: SCE's annual Advice Letter proposing 1998 PBR rate adjustment AL 1256-E

December 1997: SCE files A.97-12-047 on PBR standards for maintenance, repair and replacement

March 31, 1998: SCE files its 1997 Performance Review advice letter 1302-E

July 23, 1998: Commission issues D.98-07-077 which finds SCE's electric reliability PBR incentives to comply with D.96-09-045 requirements regarding systemwide reliability, and that SCE's customer satisfaction PBR complies with D.96-09-045 on an interim basis, regarding frequent customer requests

August 6, 1998: Commission issues D.98-08-015 finding SCE's PBR complies with D.96-11-021 regarding performance standards for maintenance, replacement, & repair

November 2, 1998: SCE files its annual AL proposing 1999 PBR rate adjustment, AL 1345-E

March 1, 1999: SCE files its PBR Midterm Review Application, A.99-03-020

March 31, 1999: SCE files its 1998 Performance Review advice letter 1373-E

June 1, 1999: SCE files supplement to its 1997 and 1998 performance review advice letters, ALs 1302-E-A and 1373-E-A

July 16, 1999: SCE files second supplement to it 1997 PBR performance review, AL 1302-E-B

September 16, 1999: Commission issues D.99-09-070 adopting a revenue sharing mechanism for Other Operating Revenues (see below), removes OOR revenues and expenses from the distribution PBR

November 1, 1999: SCE files its annual advice PBR update advice letter 1414-E, adjusting its rates for 2000

December 16, 1999: Commission issues D.99-12-035 on SCE's PBR Midterm Review A.99-03-020, finding that no adjustments to the PBR are necessary at that time but orders that certain data be prepared

March 31, 2000: SCE files AL 1449-E on 1999 PBR performance

April 6, 2000: Commission issues Resolution E-3656 on SCE's 1997 PBR performance, ordering SCE to recalculate its revenue sharing amounts

May 5, 2000: SCE files its recalculated revenue sharing amounts for 1997 PBR performance

SCE Distribution PBR Upcoming Events

November 2000: SCE to file its annual PBR update advice letter for 2001 rates

December 2000?: SCE may file 2002 GRC and application for new or modified PBR starting 2002, including reports and data ordered in D.99-12-035

March 2001: SCE files report on 2000 PBR performance
SoCalGas Base Rate PBR
June 1, 1995: SoCalGas files A.95-06-002 proposing Base Rate PBR
July 16, 1997: Commission adopts Base Rate PBR in D.97-07-054
August 22, 1997: SoCalGas files AL 2617, submitting tariff language, followed by AL 2617-A on October 1, 1997
October 1, 1997: SoCalGas files AL 2633, setting forth 1998 revenue requirement, followed by AL 2633-A on October 9, 1997
December 3, 1997: Commission approves SoCalGas 1998 PBR revenue requirement in Resolution G-3229
January 1, 1998: SoCalGas Base Rate PBR became effective
October 1, 1998: SoCalGas files first annual PBR update AL 2747, setting forth 1999 PBR revenue requirement
October 1998: SoCalGas files its BCAP Application A.98-10-012, including testimony on the base rate PBR midterm review
July 10, 1999: SoCalGas to file its final 1998 PBR Performance Advice Letter 2825
December 2, 1999: Commission issues Resolution G-3270 approving the 1998 PBR performance review report
April 20, 2000: Commission decision in SoCalGas BCAP, including findings on SoCalGas PBR
July 10, 2000: SoCalGas files AL 2938 on 1999 PBR performance

SoCalGas Base Rate PBR Upcoming Events

October 2000: PBR Update Advice Letter for 2001 revenue requirements
July 2001: SoCalGas files report on 2000 PBR performance
December 2001?: SoCalGas files 2003 GRC and application for new PBR
Pacificorp Base Rate PBR
December 2, 1992: Pacificorp files A.92-12-006 proposing Base Rate PBR
December 3, 1993: Commission adopts Pacificorp PBR in D.93-12-016
October 14, 1994: AL 262-E filed to implement 1995 price change
October 16, 1995: AL 266-E filed to implement 1996 price change
November 14, 1996: AL 276-E filed to implement price change for 1997, but asks for suspension until after submission of Pacificop Cost Recovery Plan
June 27, 1997: Pacificorp files AL 285-E to request approval of a PBR Memo Account
January 29, 1998: Pacificorp files AL 291-E to implement 1998 price change
February 3, 1998: Pacificorp withdraws AL 276-E and 285-E
January 27, 1999: Pacificorp files AL 297-E to implement 1999 price change
June 24, 1999: Commission issues Resolution E-3615 approving AL 297-E
1999: Pacificorp files application to sell its California utility assets to NorCal Electric
Pacificorp PBR Upcoming Events
Commission to decide on Pacificorp's application to sell its California utility assets
Southwest Gas Alternative Ratemaking Mechanism
January 21, 1994: Southwest proposes Alternative Ratemaking PBR in A.94-01-021
December 7, 1994: Alternative ratemaking adopted in D.94-12-022
September 3, 1998: Commission issues D.98-09-030, granting Southwest's request that its authorized rate of return adopted in D.94-12-022 be maintained and that further review of its ROR and cost of capital be integrated into its next GRC filing
February 26, 1999: Southwest files Petition to Modify D.94-12-022 to extend the GRC filing cycle pending resolution of Southwest's Northern California Expansion Project and a proposed merger
SDG&E Original Gas Procurement PBR
October 16, 1992: SDG&E files Gas Procurement PBR proposals A.92-10-017
June 23, 1993: Commission adopts PBR in D.93-06-092
October 31, 1994: SDG&E files "Year 1" annual performance review report

April 26, 1995: Commission issues D.95-04-051, adopting an indefinite extension of the gas PBR
October 31, 1995: SDG&E files "Year 2" annual performance review report
December 20, 1995: Commission issues D.95-12-047 adopting a Year 1 gas PBR reward
February 29, 1996: Vantage Consulting issues evaluation report of gas PBR
April 8, 1996: SDG&E files AL 1010-G, requesting revision in method to calculate price index
October 31, 1996: SDG&E files "Year 3" annual performance review report
February 5, 1997: Commission issues D.97-02-012 extends gas PBR, adopts modifications, and orders application for a new gas PBR
June - September 1997: Workshops held to discuss new gas procurement PBR
October 31, 1997: SDG&E files "Year 4" gas procurement review report
January 14, 1998: ORA issues analysis report for Year 4
August 6, 1998: Commission issues D.98-08-038, adopting new gas PBR and method for approving past rewards and penalties
September 8, 1998: SDG&E submits AL 1116-G, requesting approval of gas PBR rewards for Years 2, 3, and 4
October 30, 1998: SDG&E files Year 5 annual performance review report
January 15, 1999: ORA submits analysis report for Year 5
January 20, 1999: SDG&E submits AL 1134-G requesting approval of Year 5 reward
March 18, 1999: Commission issues Resolution G-3252 approving Year 5 reward

SDG&E New Gas Procurement PBR

September 30, 1997: Application No.97-09-049 for new gas procurement PBR filed by SDG&E
August 6, 1998: Commission issues D.98-08-038, adopting new gas PBR
November 12, 1999: SDG&E submits report for Year 6
April 26, 2000: ORA submits analysis report for Year 6, recommends reduction in shareholder reward

Upcoming Events for SDG&E New Gas Procurement PBR

October 31, 2000: SDG&E to submit report for Year 7
January 2001: ORA to submit its analysis of Year 7

SoCalGas Gas Cost Incentive Mechanism PBR (GCIM)

October 20, 1993: SoCalGas files GCIM proposal in A.93-10-043
March 16, 1994: Commission adopts PBR in D.94-03-076
June 15, 1995: SoCalGas files Annual Report for Year 1, A.95-06-043
January 10, 1996: Commission issues D.96-01-003, adopts Year 1 reward
June 15, 1996: SoCalGas files A.96-06-029 for GCIM review of Year 2
June 11, 1997: Decision D.97-06-061 issued, extends PBR to 3/31/99, adopts Year 2 reward, modifies GCIM, eliminates SIM
June 15, 1997: SoCalGas files A.97-06-025 reviewing "Year 3" GCIM results
December 1997: ORA files evaluation of SoCalGas "Year 3" results
April 6, 1998: SoCalGas files AL 2700 to reflect modifications adopted in D.97-06-061 and to streamline the tariffs
June 4, 1998: Commission issues D.98-06-024 approving reward for Year 3
June 15, 1998: SoCalGas files report on Year 4 GCIM results
September 23, 1998: ORA submits report on Year 4
October 27, 1998: SoCalGas files AL 2757 regarding sales of excess core gas
December 17, 1998: Commission issues D.98-12-057 approving reward for Year 4 and extending the GCIM on an annual basis beginning in Year 6
June 15, 1999: SoCalGas files report on Year 5 GCIM results
August 5, 1999: SoCalGas files AL 2836 to incorporate PITCO and POPCO supplies into GCIM (AL 2836-A filed August 25, 1999)
September 30, 1999: ORA issues report on Year 5
June 8, 2000: Commission issues D.00-06-039, approving Year 5 reward, and ordering staff to conduct evaluation report of GCIM by January 1, 2001

June 15, 2000: SoCalGas files Year 6 GCIM report
SoCalGas GCIM Upcoming Events

Fall 2000: ORA to issue analysis of GCIM Year 6

January 1, 2001: Energy Division to issue evaluation report on GCIM

PG&E Core Procurement Incentive Mechanism (CPIM)
December 29, 1994: PG&E files original application for CPIM
April 23, 1996: PG&E and DRA agree on revisions to CPIM
August 21, 1996: PG&E files Gas Accord application A.96-08-043
October 18, 1996: PG&E files supplemental report describing the post-1998 CPIM
August 1, 1997: Commission approves Gas Accord in D.97-08-055, includes CPIM approval
August 11, 1997: PG&E files AL 2032-G providing tariff revisions for CPIM
November 19, 1997: Commission approves AL 2032-G in Resolution G-3288
September 10, 1998: PG&E submits CPIM performance report for 1994 through 1997
January 15, 1999: PG&E submits CPIM performance report for January through October 1998
May 17, 1999: ORA submits audit of PG&E 1994-97 CPIM performance
October 7, 1999: PG&E submits ALs 2189-G and 2190-G requesting approval of shareholder reward for 1994-97 performance and performance from January through October 1998, respectively
January 31, 2000: PG&E submits CPIM performance report for November 1998 through October 1999

Upcoming CPIM Events

Summer 2000: ORA to file analysis of CPIM results for November 1998 through October 1999
January 2001: PG&E to file report on CPIM results for November 1999 through October 2000
Spring/summer 2001: ORA to conduct "significant review" of CPIM
SDG&E Electric Generation and Dispatch PBR
June 23, 1992: Commission adopts G&D PBR in D.93-06-092
October 31, 1994: SDG&E files first Annual Report on Year 1 results
April 26, 1995: Commission issues D.95-04-051, extends G&D PBR
September 7, 1995: Commission issues D.95-09-055, adopting minor change in filing of annual reports
October 31, 1995: SDG&E files Annual Report on Year 2 results
December 20, 1995: Commission issues D.95-12-047, adopts Year 1 reward
July 29, 1996: SDG&E files Annual Report on Year 3 results
December 18, 1996: Memorandum of Understanding signed by ORA and SDG&E, includes provision for termination of G&D PBR, agrees to Year 2, 3, and 4 reward amounts
July 16, 1997: Commission issues D.97-07-064, orders that G&D PBR terminate no later than December 31, 1997, orders final SDG&E evaluation of G&D PBR on March 30, 1998
July 31, 1997: SDG&E files Annual Report on Year 4 results
December 31, 1997: SDG&E G&D PBR terminates
March 30, 1998: SDG&E files final evaluation report for G&D mechanism
December 3, 1998: Commission issues D.98-12-004, allowing rewards for Years 2 and 3, but eliminating rewards for Years 4 and 5

SCE's Gross Revenue Sharing Mechanism for Other Operating Revenues (OOR)

June 12, 1997: SCE files A.97-06-021 requesting to adopt a revenue sharing mechanism for certain OOR.
August 10, 1998: A.97-06-021 was held in abeyance until the Commission adopted a significant modification of Rule VII of the Affiliate Transaction Rules in D.98-08-035.
October 7, 1998: SCE and ORA filed their motion for adoption of a settlement. The settlement proposed utilizing a sharing mechanism based on gross revenue and two sharing allocations - "active" and "passive".
February 8, 1999: Commission held a prehearing conference.
September 16, 1999: Commission issues D.99-09-070 that conditionally adopted a settlement between SCE and ORA. Clarification was made to when SCE could change the designation of a category or products and services from "passive" to "active", and certain other procedural matters addressed in the settlement.
September 28, 1999: SCE requested an extension of 30 days to comply with Ordering Paragraph 4 of D.99-09-070. Ordering Paragraph 4 required SCE to file an Advice Letter that would modify its Preliminary Statement and to describe the OOR incentive mechanisms in its Preliminary Statement.
October 1, 1999: Commission's Executive Director grants extension.
October 31, 1999: SCE files Advice Letter 1413-E.
January 24,2000: SCE files supplemental Advice Letter 1413-E-A. This Advice Letter revised the Preliminary Statement filed in Advice Letter 1413-E to included two new sections entitled "Advice Letter Process, " and "Approved Non-Tariffed product and Services"; and Part N, Memorandum Accounts.
February 16, 2000: Advice Letter 1413-E and supplemental Advice Letter1413-E-A are approved with an effective date of September 16, 1999 as ordered by D.99-09-070.

PG&E's Net Revenue Sharing Mechanism for New Non-tariffed Products and Services

August 10, 1998: Commission issues D.98-08-035 that modifies Rule VII of the Affiliate Transaction Rules.
May 4, 1998: PG&E files A.98-05-007 requesting authorization to adopt a net revenue sharing mechanism and other prerequisites for new non-tariffed products and services.
November 12, 1998: PG&E files PBR A.98-11-023.
April 1, 1999: Commission issues D.99-04-021 that adopted A.98-05-007 on an interim basis. PG&E is ordered to file supplemental testimony in A.98-11-023 describing a permanent revenue sharing mechanism for new non-tariffed products and services.
May 9, 1999: PG&E files supplemental testimony to A.98-11-023.
March 30, 2000: PG&E files a petition to withdraw A.98-11-023. PG&E requested that the Commission, in its decision granting this petition, would allow the interim net revenue sharing mechanism approved in D.99-04-021 to continue in effect until further order of the Commission.
June 22, 2000: Commission issues D.00-06-058 granting PG&E's petition to withdraw A.98-11-023. D.00-06-058 orders PG&E to include a permanent revenue sharing mechanism in its September 1, 2000 PBR application.

APPENDIX 2

PBR MECHANISMS ADOPTED BY THE COMMISSION WHICH HAVE EXPIRED

The following PBRs had been adopted by the Commission in the past, and have either been replaced by new PBRs or have terminated. The PBRs discussed below are:

1. SDG&E's original base rate PBR
2. Pacificorp's base rate PBR
3. SDG&E's Generation and Dispatch PBR
4. SDG&E's original gas procurement PBR
5. PG&E's original Core Procurement Incentive Mechanism

I. SDG&E's Original Base Rate PBR

Adopted in D.94-08-023 (A.92-10-017), San Diego Gas & Electric's Base Rate PBR mechanism eliminated SDG&E's 1996 GRC, and had a term from 1994 to 1998. [35] The adopted Base Rate PBR was composed of four main components: 1) formulas for developing an annual revenue requirement; 2) a revenue sharing procedure; 3) performance indicators; and 4) a monitoring and evaluation program. "Z-factors" were not specifically addressed in the SDG&E base rate PBR, but petitions for modifications may be made to adjust the revenue requirement for factors "beyond management control, that clearly and materially affect the revenue requirement". Applications for "material external events" may also be made to allow for costs in certain specifically-named areas. (As discussed later, the Commission has adopted a new base rate PBR for SDG&E, effective January 1999, in D.99-05-030.)

I.A. SDG&E Original Base Rate PBR Revenue Requirement

SDG&E's original base rate PBR was applied to both the utility's gas and electric departments, and currently to all of the electric utility system (i.e., generation, transmission, and distribution). It used a "revenue indexing" method. The utility's annual revenue requirement was adjusted using formulas for revenue requirement associated with authorized operating and maintenance expenses (O&M) and for the determination of PBR-authorized capital costs and associated expenses. Electric O&M and gas O&M were calculated separately, and expenses associated with nuclear operations and Major Additions Adjustment Clause (MAAC) provisions were excluded. The SDG&E PBR originally allowed nuclear O&M expense as the proportionate share of the O&M amount authorized for Southern California Edison, plus appropriate overheads, but nuclear O&M expense and San Onofre Nuclear Generating Station (SONGS) capital additions were removed from the SDG&E PBR in 1996 as a result of D.96-04-059. [36]

The experimental PBR mechanism drew on the framework of the attrition mechanism which the CPUC formerly used to establish SDG&E's revenue requirements for non-GRC years. Like the attrition mechanism, the revenue cap started from the most recently authorized revenue requirement which, in this case, was SDG&E's 1993 test year GRC. Each year the revenue cap was established by adjusting the prior year's cap for O&M changes related to inflation and customer growth, with an offset for productivity, and for changes in PBR-authorized capital costs and associated expenses. The O&M formula included a productivity growth factor set at 1.5% per year.

Transmission and distribution ("T&D") capital costs were estimated using a regression equation which was based on the changes in total plant additions per year, and the relationship between customer growth and plant additions. All expenses relating to non-nuclear generation capital additions were determined through a three-year historical average. The authorized rate of return ("ROR") on the associated rate base additions for distribution, transmission and generation plant has been determined in the CPUC's annual cost-of-capital proceeding which involves all investor owned energy utilities.[37]

However, in 1996, the Commission adopted in D.96-06-055 a mechanism by which to adjust the SDG&E ROR (using a Market Indexed Capital Adjustment Mechanism, or MICAM), but the MICAM was not applicable to the SDG&E PBR until 1998.[38]

SDG&E could petition to modify the base rate revenue requirement if events outside of management's control generate a change (either positive or negative) of $500,000 or greater. These exogenous factors included catastrophic events, changes in tax laws, hazardous waste cleanup, or changes in environmental regulations.

I.B. SDG&E Original Base Rate PBR Revenue Sharing Mechanism

The sharing mechanism compared SDG&E's actual annual rate of return ("ROR") to its authorized ROR for the same calendar year. Rather than passing along overruns in the form of increased rates, the utility had the incentive to reduce operating costs and thus increase its shareholder's profits and/or lower rates. The mechanism used combined gas and electric returns, then allocated any shared returns on the basis of the adopted allocation of 1993 authorized base rate revenues (84% electric, 16% gas). Sharing was asymmetric and had three tiers:

· SDG&E shareholders retained all revenue gains up to 100 basis points above the benchmark authorized ROR. (SDG&E shareholders were also responsible for all losses below the benchmark.)

· If SDG&E's actual ROR was between 100 and 150 basis points above its authorized ROR, gains were shared between ratepayers (25%) and shareholders (75%).

· If actual ROR was between 150 and 300 basis points above authorized ROR, gains were shared equally (50/50) between ratepayers and shareholders.

Actual ROR 300 basis points above or below the benchmark would have triggered an automatic suspension of the PBR and a formal regulatory review of the PBR and/or a GRC review.

I.C. SDG&E Base Rate PBR Performance Indicators

SDG&E's base rates mechanism included three nonprice performance indicators which reward or penalize the utility's performance measured against an established benchmark in employee safety, customer satisfaction, and system reliability. In the originally-adopted SDG&E PBR, a price performance indicator was also included, which compared the utility's system average rate with a national index and rewarded or penalized accordingly. However, in D. 97-09-052, the Commission eliminated the price performance indicator, effective January 1, 1997, due to a legislatively-imposed electric price freeze. The maximum yearly reward for the performance indicators was $19 million, and the maximum yearly penalty was $21 million, but with the elimination of the price performance indicator the maximum reward is now reduced to $9 million, and the maximum penalty is reduced to $11 million.

<u>Employee Safety</u>

For employee safety, the maximum reward was $3 million and the maximum penalty was $5 million. The standard was derived from Occupational Safety Health Administration's (OSHA's) lost time accident frequency, which measures the company's total employee loss time against total employee working hours. The benchmark was 1.20 units lost time, which was arrived at based on SDG&E's historical averages. The $3 million reward was allowed if actual performance met or was less than an OSHA loss time frequency of 1.17, with smaller rewards of $1.5 million and $0.5 million for performance leading to frequencies of 1.18 and 1.19, respectively. Penalties above the OSHA benchmark were higher: A $1 million penalty was assessed for a frequency of 1.21, $2.7 million for a frequency of 1.22, and $5 million for a frequency of 1.23 or higher.

<u>Customer Satisfaction</u>

The customer satisfaction indicator utilized SDG&E's Customer Service Monitoring System (CSMS) results from the prior year, and had a benchmark of 92% "very satisfied" responses from customers surveyed. Rewards and penalties increased symmetrically in increments of $0.67 million for each percentage point above or below the benchmark. The maximum reward or penalty was $2 million for 95% or 89% "very satisfied," respectively. SDG&E's CSMS has been in place since the 1970's and customer responses number over 10,000 per year. The survey is structured to measure customer satisfaction tied to specific service quality issues rather than general opinions about rates or public image. To ensure validity, the annual CSMS data was audited by an unbiased third-party.

<u>System Reliability</u>

The System Reliability indicator benchmark utilized SDG&E's System Average Interruption Duration Index ("SAIDI"). The index measured the average annual duration of certain service interruptions per customer, excluding major events such as earthquakes and severe storms. The maximum annual reward or penalty was $4 million for performance of 50 minutes or 90 minutes, respectively. The benchmark was 70 minutes. Each intermediate minute was worth $200,000 in rewards or penalties.

<u>Price Performance</u>

In the originally-adopted PBR, the Price Performance indicator compared SDG&E's annual system average electric rates to a national average rate of investor-owned electric utilities. A reward or penalty was assessed depending on how SDG&E's electric rates compared to the national average, as measured by statistics published by the Edison

Electrical Institute. The benchmark was set at 137% of the national average for 1994, with a deadband of plus or minus 1%. The maximum reward or penalty for this benchmark was $10 million. The national average benchmark declined by about a percentage point per year over each year of the PBR's term. The benchmark was 136% for 1995, and 135% for 1996, and was expected to be 133% for 1997, and 132% for 1998. The reward or penalty changed by $1 million for each half-percentage point increase or decrease in SDG&E's rates compared to the national average.

As noted above, the Commission eliminated the price performance indicator in D.97-09-052, due to the imposition of a electric price freeze, effective January 1, 1997.

Conditionality

In the originally-adopted PBR, a two-way "conditionality" mechanism conditioned any reward for price performance on SDG&E's non-price performance, and vice versa. With the elimination of the price performance indicator in 1997, the conditionality component was also consequently eliminated.

Conditionality reduces price performance rewards the utility would otherwise earn if it is assessed a nonprice penalty in the aggregate. Conversely, nonprice rewards will be reduced if SDG&E is assessed a price performance penalty. Penalties are not similarly offset.

The conditionality steps were:

1. Calculate rewards/penalties for price and non-price performance indicators based on the utility's performance during the prior year. The price performance indicator is the National Rate Comparison. The non-price performance indicators are the total incentives from Employee Safety, Customer Satisfaction, and System Reliability.
2. If rewards are achieved for both price and the total non-price performance indicators, then no conditionality adjustment is made.
3. If penalties are received for both price and the total non-price performance indicators, then no conditionality adjustment is made.
4. If rewards are achieved for total non-price performance indicator and penalties are received for price performance indicator, then the total non-price rewards calculated in step 1 are reduced by a corresponding "non-price multiplier".
6. If rewards are achieved for price performance indicator and penalties are received for total non-price performance indicator, then the price rewards calculated in step 1 are reduced by a corresponding "price multiplier".

I.D. SDG&E Base Rate PBR Monitoring and Evaluation

The Monitoring and Evaluation ("M&E") component of the base rates mechanism was designed to judge the mechanism's initial progress, unintended consequences, and/or ultimate success. The M&E process gathered information through semi-annual reports (due September 15th & May 15th), and a mid-point review, which was envisioned to permit "fine-tuning" of the data collection process[39] and possibly modifications to the mechanism, and determine whether a 1999 GRC was necessary. On May 15th, SDG&E provided annual evaluations giving management's view of the degree of success of the experiment. SDG&E also filed an advice letter on October 15th which provided the utility's calculation of PBR revenue requirements for the following year. The M&E plan allowed the CPUC to make an independent assessment of the PBR mechanism. The M&E process was intended to provide the necessary information as to whether the experimental mechanism should be made permanent, modified, abandoned or replaced with a GRC review or some other regulatory plan.

I.E. SDG&E Base Rate PBR Results

Table B-1

PBR Performance Indicator Benchmarks and Results (1994-1996)

Performance Indicators	**1994**		**1995**		**1996**	

	Benchmark and Range	Actual	Benchmark and Range	Actual	Benchmark and Range	Actual
Rate of Return	9.03%	9.99%	9.76%	11.13%	9.07%	10.65%
Safety (LTA)	1.20 $\pm$ 0.03	1.04	1.20 $\pm$ 0.03	0.90	1.20 $\pm$ 0.03	0.98
Reliability (min.)	70 $\pm$ 20	70	70 $\pm$ 20	67.5	70 $\pm$ 20	77.5
Customer Satisfaction (%)	92 $\pm$ 3	95	92 $\pm$ 3	95.2	92 $\pm$ 3	95.4
Price Performance (%)	137.0 $\pm$1	135.1	136.0 $\pm$ 5	135.9	135.0 $\pm$ 5	133.5

Table B-1
PBR Performance Indicator Benchmarks and Results (1997-1998)

Performance Indicators	**1997**		**1998**			
	Benchmark and Range	**Actual**	**Benchmark and Range**	**Actual**		
Rate of Return	8.99%	10.59%	8.90%	8.20%		
Safety (LTA)	1.20 $\pm$ 0.03	1.17	1.20 $\pm$ 0.03	1.15		
Reliability (min.)	70 $\pm$ 20	91.4	70 $\pm$ 20	99.3		
Customer Satisfaction (%)	92 $\pm$ 3	93.2	92 $\pm$ 3	93.4		
Price Performance (%)	NA	NA	NA	NA		

Table B-2
PBR Performance Indicator Rewards/Penalties (1994-1996)

Performance Indicators	**1994** Reward/(Penalty)	**1995** Reward/(Penalty)	**1996** Reward/(Penalty)
ROR Basis Points Above/(Below) Authorized	96 Points	137 Points	158 Points
Safety	$3,000,000	$3,000,000	$3,000,000
Reliability	$0	$500,000	($1,500,000)
Customer Satisfaction	$2,000,000	$2,000,000	$2,000,000
Price Performance	$2,000,000	$0	$3,000,000
Conditionality	None	None	None
Total Reward/ (Penalty)	$7,000,000	$5,500,000	$6,500,000

Table B-2
PBR Performance Indicator Rewards/Penalties (1997-1998)

Performance Indicators	**1997**	**1998**	

	Reward/(Penalty)	Reward/(Penalty)	
ROR Basis Points Above/(Below) Authorized	160 Points	(70) Points	
Safety	$3,000,000	$3,000,000	
Reliability	($4,000,000)	($4,000,000)	
Customer Satisfaction	$666,667	$1,000,000	
Price Performance	NA	NA	
Conditionality	NA	NA	
Total Reward/ (Penalty)	($333,333)	$0	

II. Pacificorp Base Rate PBR

The Commission adopted Pacificorp's Base Rate PBR in D.93-12-016 (A.92-12-006). Under this mechanism, Pacificorp's annual electric price changes were based on a utility-wide cost escalation index offset by productivity gains as indicated by the utility-specific level of Total Factor Productivity (TFP) growth. The annual price change indicated by the price index was allowed unless the utility's average California price exceeded 105% of the national average for investor-owned electric utilities. The mechanism was extended through the 1997-1999 rate case cycle. In D.97-12-093, the Commission expected Pacificorp to file a new PBR application for a PBR to become effective January 1, 2000. However, in August 1999, Pacificorp filed its application A.99-08-036 with the Commission to sell its California utility assets to NorCal Electric. The Commission has not yet issues a decision on Pacificorp's application.

II.A. Pacificorp Base Rate PBR Price Index

Cost escalation was estimated using four price indices taken from DRI/McGraw Hill's Review of the US Economy weighted by the utility's cost structure. Cost escalation was offset by productivity gains as indicated by the Company-specific level of Total Factor Productivity growth (TFP)[40]. The utility-wide escalation index was calculated annually. The average TFP for the period 1972 - 1996 provided the productivity adjustment for 1995 and 1996.

For the period 1997 through 1999, two adjustments to the TFP were made. First, three years of actual data (1992 - 1994) replaced three years of forecast data in the TFP calculation. Second, three additional years of forecast data (1997 - 1999) were added to the interval over which the TFP is calculated. The new average TFP for 1972 - 1999 provided the productivity adjustment for 1997 - 1999. This figure was 1.5% for 1997 to 1999.

In addition to index adjustments there were allowances for prices changes due to either (1) changes in state or federal income tax rates or (2) enactment of an energy related tax. The mechanism provided that the increase indicated by the price index is implemented unless Pacificorp's average California electricity price exceeded 105% of the national average electricity price for investor-owned utilities as published by Edison Electric Institute (EEI)

II.B. Pacificorp Base Rate PBR Results

> For 1995, Pacificorp's PBR indicated in a 2.4% price increase, but Pacificorp requested only a 1.5% increase due to "competitive issues and a desire to moderate price impacts for residential customers". It also requested that it be allowed to utilize the foregone price increase in future years. For 1996, the PBR resulted in a 1.25% price increase, which Pacificorp requested. Pacificorp continued to defer the price increase foregone in 1995. For 1997, Pacificorp's PBR indicated in a 2.96% price increase.

III. SDG&E Electric Generation and Dispatch (G&D) PBR Mechanism

III.A. SDG&E's G&D PBR Operation

The SDG&E Generation and Dispatch (G&D) PBR was adopted by the Commission in D.93-06-092 (A.92-10-017). Originally, the G&D PBR had a two-year term, but the Commission extended the mechanism's term.[41] In D.97-06-064, the Commission allowed the G&D PBR to continue through December 31, 1997. The Commission also noted that termination could occur earlier than December 31, 1997, depending on the outcome of a pending decision in SDG&E's ECAC A.96-10-022.

The Electric Generation and Dispatch mechanism measures how effectively SDG&E buys power, and operates and dispatches its generating units. The mechanism operates within the framework of the Commission's annual two-phase ECAC proceeding, in which a utility's projected fuel and fuel-related costs for electric operations are forecast and then compared with actual costs.

First, rates for a future 12-month period are established based on a production cost simulation using forecasts of a number of variables affecting purchased power, fuel and production costs. The variables are:

1) Sales (MWH) and Peak (MW)
2) Gas/Oil Prices
3) Qualifying Facilities' Costs and Purchases
4) Fossil Unit Heat Rate
5) Nuclear Generation and Cost
6) Power Purchase Capacity Costs
7) Transmission Wheeling Costs/Revenues
8) Long-term Firm Contract Cost
9) Short-term Firm Contract Cost
10) Economy Energy Cost
11) Fossil Unit Availability

After all of the variables have been forecast, production cost simulation is developed using a computer model (ELFIN) that dispatches SDG&E's own system resources and otherwise-available resources, based on cost and availability.

Each month that follows the annual forecast production cost simulation, the model is re-run. In this new simulation, several of the variables are updated (i.e., "trued-up") to reflect actual experience for the preceding month. These variables are updated for categories of costs and operating conditions that are largely beyond a SDG&E's control. The subsequent simulations retain the initial forecasts for the cost and operating variables over which SDG&E exercises greater control.

The remaining variables are the focus of the mechanism's "performance" measurement. These latter variables are those in **bold** on the above list. Once the model is "trued-up" a benchmark is produced for each month of the year. Actual operating costs for the same period are then compared to the benchmark costs to determine SDG&E 's performance. If actual costs are above the benchmark, the utility shares in the proportionate cost. Shareholders retain 30% of the savings and bear 30% of the costs that underrun or overrun the benchmark by 1% or less. Savings or excess costs between 1% and 6% over or under the benchmark are shared equally by shareholders and ratepayers. If the SDG&E's performance falls outside the 6% range, a reasonableness review is triggered.

III.B. Monitoring and Evaluation

SDG&E sends quarterly reports to the Commission which summarize its performance under the G&D PBR. On July 31st, SDG&E files its annual performance report summarizing its annual performance results, including the calculation of any rewards or penalties. Interested parties then have an opportunity to respond to SDG&E's report. Only ORA has responded to SDG&E's Year 1 and Year 2 reports, and no party responded to the Year 3 filing. No party has yet responded to the Year 4 filing. However, ORA and SDG&E signed a Memorandum of Understanding (MOU) on December 18, 1996 which settles on certain rewards allowed under the G&D PBR for Years 2, 3, and 4. Rewards or penalties are supposed to be approved by the Commission in SDG&E's ECAC proceeding, but only a Year 1 reward has been adopted to date. As noted earlier, SDG&E's ECAC decision has been eliminated. Further, no 1997 forecast ECAC proceeding has been conducted, so no G&D PBR benchmarks have been established for the period beyond April 30, 1997.42

III.C. Results

Table B-3
Summary of Results of SDG&E's G&D PBR
($ in 1000's)

	Year 1	Year 2 Year 3 Year 4 Year 5
Basis for Reward ($ mil.)	**496,561.7**	**$475,586.3 $349,861.3 See below See below**
Actual for Year ($ mil.)	**$487,203.9**	**$472,750.4 $319,849.6**
Variance ($ mil.)	**$9,357.8**	**$2,835.9 $30,011.8**
Shareholder Reward	**$3,685.8**	**$850.8 $9,796.1**
Ratepayer Savings	**$5,672.0**	**$1,985.1 $20,215.7**

The results for Year 1 were approved by the Commission. The above rewards for Years 2 and 3 were consolidated with other rewards by the Commission in D.98-12-004. That same decision allowed no rewards for Years 4 and 5 pursuant to a settlement between SDG&E and ORA.

IV. PG&E CPIM for the Period Prior to 1/1/98

The pre-98 CPIM compares PG&E actual core procurement costs to an established benchmark of reasonable costs, and a deadband constructed around the total cost benchmark. Actual costs or savings outside the deadband were intended to be shared equally between ratepayers and shareholders.43 Actual costs within the deadband are
entirely recoverable from ratepayers.

IV.A. Pre-1998 PG&E CPIM Fixed Demand Charges

PG&E's fixed core demand charges on El Paso, ANG, NOVA, and PGT are included in the benchmark as reasonable costs, and may be included as actual costs. However, no Transwestern demand charges may be included in either the benchmark or as actual costs. 44 PG&E foregoes the recovery of any Transwestern demand charges from core ratepayers.

IV.B. Pre-1998 PG&E CPIM Weighting of Benchmark Commodity Purchase Price

Published price indices for southwest and gas market purchases are used to establish a benchmark price for PG&E's interstate gas purchases. In the winter months, the southwest price and the Canadian price are weighted equally, but in the summer months, the lower of the two prices is weighted 75%, while the higher price is weighted 25%. The basin index weightings were based on PG&E's historical purchasing pattern.

The benchmark price for California gas purchases is a formula called the "fair market price" formula, which PG&E has generally used to arrive at the price it pays to California suppliers.

IV.C. Pre-1998 PG&E CPIM Tolerance Band

The amount of the tolerance band, or deadband, above the total cost benchmark is 2.5% of the total commodity cost benchmark. The amount of the deadband below the total cost benchmark is 1% of the commodity cost benchmark.

IV.D. Pre-1998 PG&E CPIM Capacity Brokering

In order to provide PG&E with an incentive to broker core capacity when warranted, the aggregate benchmark is reduced by $3 million plus the revenue from the direct assignments to core aggregators on PGT and El Paso in 1996, and $4 million plus the revenue from the direct assignments to core aggregators on PGT and El Paso in 1997.

IV.E. Pre-1998 PG&E CPIM Monitoring and Evaluation

The pre-1999 CPIM agreement between ORA and PG&E included the following provisions for monitoring and evaluation: PG&E would send quarterly and annual reports to the Commission summarizing its performance, 90 days after the last calendar date of each quarter. Annual calculations of the rewards or penalties would occur in the annual report. The Commission was expected to audit the results, and ORA and CACD would have an opportunity to each issue reports in response to PG&E's annual performance filing. Interim evaluation reports were expected to be filed, after each of the expected two years of operation, and a final evaluation report was expected after the third year. However, the pre-1998 CPIM was not officially approved by the Commission until August 1998, so little monitoring and evaluation has been conducted to date.

IV.F. Pre-1998 PG&E CPIM Results

PG&E has not officially filed its CPIM performance results in any CPUC proceeding to date, due to the lengthy delay in obtaining CPUC approval of the CPIM. However, PG&E provided the following preliminary results through September 1997 to the Energy Division.

Table B-4
PG&E CPIM Results
($ in 1000's)

Year	Actual Costs	Benchmark Costs	Upper Tolerance	Lower Tolerance	Below/(Above) Tolerance	Reward/(Penalty)
1994*	$342,798	$344,479	$351,285	$341,758	Within band	0
1995	$458,084	$454,570	$462,913	$451,233	Within band	0
1996	$535,243	$560,059	$570,627	$555,832	$20,588	$10,294
1997*	$445,623	$476,948	$486,252	$473,226	$27,604	$13,802

*The above 1994 figures are only for the period June 1994 through December 1994, and the above 1997 figures are only for the period January 1997 through September 1997.

While the above CPIM results indicate that PG&E has incurred actual costs below the lower tolerance range in 1996 and 1997, PG&E is not entitled to a reward for 1996 performance, and any actual reward for 1997 will be much smaller than indicated above. For 1997, PG&E's tariff provides that any reward will be the lesser of the following: a) the award for the aggregate CPIM performance based on a benchmark calculated only for those full months that occurred in 1997, following approval of tariffs implementing the pre-1998 CPIM; or b) the annual award for 1997 prorated for the number of full months that occurred in 1997, following approval of tariffs implementing the pre-1998 CPIM.

IV. Original SDG&E Gas Procurement PBR

IV.A. Original SDG&E Gas Procurement PBR Part A

The SDG&E Gas Procurement Mechanism adopted in D.93-06-092 (A.92-10-017) is divided into two separate components (Part A and Part B). Part A provides incentives to the utility to purchase gas at or below a market-based benchmark price, which is established by averaging the monthly published spot-market price for three Southwestern gas supply basins, then adding in SDG&E's actual cost of transportation to the California border. Actual Purchased Gas Costs (PGC's) are compared annually with benchmark gas costs. Any difference between the two represents the savings or costs to be shared by ratepayers and shareholders. In other words, if SDG&E beats the benchmark, the ratepayer and the shareholder share equally in the savings. Likewise, if the utility's costs exceed the benchmark, both the ratepayer and the shareholder share the excess costs.

The Part A benchmark incorporates an asymmetric "deadband" to account for gas price variability. SDG&E's gas costs may exceed the benchmark by 2% before its shareholders share in excess costs. The deadband does not extend *below* the benchmark. Any reward to shareholders, 50% of shared savings, will be included as part of the total cost of gas procurement. Conversely, shareholders' penalty amount, 50% of shared costs, will be used to reduce the purchased gas costs recoverable through rates (D. 93-96-092). Part A provides the utility a "balanced incentive to obtain competitive gas prices at the basin...if it can purchase its gas supplies at (spot) market prices. Shareholder and ratepayer interests are aligned as they are expected to share cost/savings when the utility's performance results in purchased cost above/below these market-based standards." (Id., pp. 30)

SDG&E's Canadian gas costs are included in the mechanism's actual PGC's. For volumes not purchased from Southwest basins, benchmark costs include these volumes priced at a California Border Price Index.

IV.B. Original SDG&E Gas Procurement PBR Part B

Part B of the gas procurement mechanism encourages SDG&E to make the most cost-effective gas transportation decisions based on available supply and delivery alternatives, while maintaining core service reliability. The benchmark is the weighted average of the published basin prices from Part A, plus firm transportation rates to the California border. At the end of each 12-month period, if actual costs are below the benchmark, 95% of the savings goes to customers and 5% of the difference goes to shareholders.

IV.C. Original SDG&E Gas Procurement PBR Gas Storage Component

In 1996, the Commission adopted a gas storage incentive component as part of the SDG&E gas procurement PBR. The proposal made by SDG&E in Advice Letter 1029-G became effective in November 1996. The only modification to the PBR was to change the delivery point for gas under the Part B benchmark from the California border to SDG&E's custody transfer points from SoCalGas. The Part B benchmark is calculated for storage by multiplying the Delivered Price Index times gas volumes measured at SDG&E's gas metering stations. In this manner, the Part B benchmark will include gas volumes withdrawn from storage as well as the volumes delivered for immediate customer use. This will be compared to the actual costs for the same volumes.

III.A.4. Original SDG&E Gas Procurement PBR Monitoring and Evaluation

SDG&E provides a monthly report to the Commission which summarizes its performance under the gas PBR. On October 31st, SDG&E provides its annual filing to the Commission and interested parties, summarizing the annual results of its performance, including the calculation of any rewards or penalties. ORA and other parties are then given an opportunity to review and respond to the report. Thus far, ORA has been the only party to file a responding report. Rewards or penalties for a particular calendar year are then approved in SDG&E's ECAC proceeding.45 An interim and "final" evaluation of the gas PBR was also conducted under the auspices of CACD in 1995 and 1996. Certain modifications of the gas PBR have also been proposed by SDG&E both through advice letters and petitions for modification.

III.A.5. Original SDG&E Gas Procurement PBR Results

Table 4
SDG&E Gas Procurement PBR Results
(Dollars in $1000)

	MMMBtu Purchased	Part A Benchmark Costs	Part A Actual Costs	Part A Reward/ (Penalty)	Part B Benchmark Costs	Part B Actual Costs	Part B Reward/ (Penalty)	Total Reward/ (Penalty)
Year 1	94,456	$207,303	$201,697	$2,803	$221,511	$201,697	$991	$3,794
Year 2	92,750	$150,407	$148,322	$2,085	$168,715	$148,322	$1,020	$2,062
Year 3	89,388	$132,086	$138,013	$(1,694)	$176,149	$138,013	$1,907	$213
Year 4	103,609	$262,207	$252,991	$4,608	$313,142	$252,991	$2,701	$7,309
Year	100,008	$247,641	$243,584	$2,029	$272,015	$247,311	$1,235	$1,962*

5								

* An adjustment was recommended by ORA in Year 5 to reward amounts for Year 4 storage amounts.

The above results for Years 1 through 5 have been adopted by the Commission. The results for Year 6 are shown in the section on the new SDG&E Gas PBR.

[1] See D.94-08-023, pg. 29.

[2] Base rates generally refer to the rates expected to recover a utility's expenses and costs excluding fuel and purchased power expenses.

[3] If SDG&E reports a return of 300 basis points or more below the authorized ROR, the PBR is automatically suspended and SDG&E will be required to file an application which will lead to a formal review of the mechanism. If SDG&E reports an ROR which is 150 basis points or greater below the authorized ROR, SDG&E or ORA may file for a voluntary suspension of the mechanism.

4 In 1998, the SCE PBR was adapted to become applicable only to electric distribution. 5 The 12-month average, ending in September, of Moody's Long-Term Corporate Bond Yield Averages, Average Public Utility AA.

[6] Section 463 projects (projects with expected costs over $50 million) are not excluded, but may receive Z-Factor treatment.

[7] If SoCalGas reports return of 300 basis points above authorized earnings for at least two consecutive years, the PBR is automatically suspended and a formal GRC is conducted to determine required changes in the mechanism. For downside deviations, an offramp at 175 basis points for two consecutive years makes the PBR subject to a motion for voluntary suspension by either ORA or SoCalGas.

[8] The GCIM excludes SoCalGas purchases made pursuant to a long-term supply contract, the "Enron Bank" contract. Those gas purchases were specifically dealt with in the SoCalGas "Global Settlement." PITCO and POPCO purchases were also originally excluded from the GCIM, but beginning in 1999, these contracts were restructured and purchases began to be included in GCIM actual costs.

[9] The PG&E CPIM for the period prior to 1998 is described in Appendix 2.

[10] To the extent that nominated volumes do not perform under any of the above three areas, the non-performance volumes will be included under the alternative benchmark.

[11] The proposal builds upon the sharing mechanisms adopted by the Commission for SCE's fuel oil pipeline system (SCE Pipeline and Terminal Company) in D.94-10-044 and for the commercialization of Research, Development & Demonstration products (the Technology Commercialization Incentive Procedure) in Resolution E-3484 (adopted on March 18, 1997), and upon the interim revenue sharing for telecommunication facility lease revenue adopted in D.96-07-038 and D.96-07-058. [12] SCE indicated historical examples of how it has enhanced the utilization of utility assets such as by licensing of utility rights-of-way for horticultural or mini-storage uses, the leasing of available space in fiber optic cables, and the use of maintenance shop facilities and employees to repair large machinery or perform meter testing for third parties.

[13] D.99-09-070, page 30, "Finding of Fact" number 6. [14] Accrued interest will still exist in these two memorandum accounts. [15] SCE's 2000 Revenue Adjustment Proceeding (RAP) application will included a proposal for the dispersal of the balances in these two memorandum accounts. Interest will accrued until a decision is made on SCE's 2000 RAP application. [16] See Attachment A from D.99-09-070 for the complete list of the different types of "Non-tariffed Products and Services" with their appropriate descriptions. [17] Incremental shareholder investment includes capital-related costs (i.e. purchase of property or equipment) and expenses (i.e. consultants, supplies, materials, rent, marketing materials) incurred in connection with offering non-tariffed products or services. [18] The percentage falls at the midpoint of the agreed sharing mechanisms in D.94-10-044 and Resolution E-3484. [19] D. 96-07-038 and D.96-07-058 [20] In D.99-09-070, Incremental OOR will be subject to the gross revenue sharing mechanism and using the Active Sharing Allocation or the Passive Sharing Allocation will be allocated between shareholders and ratepayers. [21] This amount was developed in SCE's 1995 Test Year GRC (D.96-01-011) [22] Interest is accrued monthly in the GRSTA by applying the interest rate to the average of the

beginning and end of the month balances. [23] The balance in the GRSTA will include any accrued interest.

[24]D.99-09-070, page 34, "Conclusions of Law" number 7.

24 [25] For example, PG&E' 1999 GRC (A.97-12-020) forecasts non-FERC OOR for 1998 and 1999 at $29.6 million and $33.5 million (Chapter 4C). [26] As of June 30, 2000, AL 2063-G/1741-E has not been closed. [27] AL 2063-G-B/1741-E-B amendments included changes of one category from non-tariffed to tariffed, and revised language to more clearly cover existing products and services in two other categories. [28] AL 2063-G-A/1741-E-A added an additional existing non-tariffed category. [29] Currently, PG&E has filed only one AL offering a new category of non-tariffed products and services, "Third-party Meter Reading Services." AL 2166-G/1890-E (Resolution E-3685) is still pending. [30] Shareholders will bear 100% of any shortfalls. [31] Non-incremental costs will not be allocated to the non-tariffed offering, since these new NTP&S will not affect these non-incremental costs. Examples are embedded asset costs and Corporate Administrative and General costs. [32] Examples are systems development and maintenance, full labor costs (salaries plus allocations for pensions, benefits, vacation time, etc.), direct supervision and management costs, vehicle costs, and cost of materials. [33] The ratepayer share of the positive net revenues will be applied as an adjustment to the authorized revenue requirement in PG&E's Transition Revenue Account (TRA). The TRA is verified annually in the Revenue Adjustment Proceeding (RAP). [34] Rule VII.H. of the Affiliate Transaction Rules requires these reports to be filed.

[35] [35] In May 1999, the Commission adopted a new base rate PBR for SDG&E, effective January 1, 1999, in D.99-05-030.

[36] The nuclear component of SDG&E's revenue requirement calculation changed significantly in 1996. After that time, nuclear O&M was no longer included in the base rate O&M calculation, and nuclear capital additions are no longer included in the calculations of rate base. In addition, the SONGS authorized rate of return is set at 7.14%. This figure was then weighted with the Commission's authorized ROR for the non-nuclear portions of SDG&E's rate base.

[37] As noted earlier, the ROR benchmark was a rate-base weighted ROR, using the authorized ROR adopted in the cost of capital proceeding, and the adopted ROR (7.14%) for SONGS.

[38] [38] The Commission adopted a new cost of capital for SDG&E and other California utilities in D.99-06-057.

[39] SDG&E and interested parties engaged in this "mid-term review" in 1997. D.97-12-041 summarized the outcome of and ended the mid-point review.

[40] Both ORA and Pacificorp note that data for 1989 reflect non-recurring productivity due to the merger of Pacific Power & Light and Utah Power & Light. The data do not reflect the increase in the combined utility's capital stock. Consequently, 1989 data are removed from the TFP calculation.

[41] See D.95-04-051, D.95-12-063, D.96-01-009, and D.97-06-064.

42 On December 9, 1997, a pre-hearing conference was held in SDG&E's ECAC A.96-10-022. SDG&E and ORA indicated that they will attempt to produce a written settlement of certain issues. 43 Pursuant to the CPIM agreement with ORA, which provided for no shareholder reward prior to CPIM implementation, PG&E shareholders are not entitled to rewards in 1996, and any rewards for 1997 are significantly reduced from the amounts resulting from the CPIM. 44 PG&E's subscription to firm Transwestern interstate pipeline capacity was found unreasonable by the Commission in D.95-12-046. 45 SDG&E's ECAC proceeding was eliminated by D.97-10-057. Another means for approval of the rewards and penalties was adopted by the Commission in D.98-08-038.